S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter, on the Commission's own motion, to open a docket to implement the provisions of Section 6w of 2016 PA 341 for **CONSUMERS ENERGY COMPANY'S** service territory.	))))))	Case No. U-18239

At the November 21, 2017 meeting of the Michigan Public Service Commission in Lansing, Michigan.

PRESENT: Hon. Sally A. Talberg, Chairman
Hon. Norman J. Saari, Commissioner
Hon. Rachael A. Eubanks, Commissioner

ORDER

History of Proceedings

On January 20, 2017, the Commission commenced this proceeding for implementation of Section 6w of 2016 PA 341 (Act 341), MCL 460.6w, for Consumers Energy Company (Consumers) and set a schedule for related filings. As a result of rulings by the Federal Energy Regulatory Agency (FERC),[1] the Commission issued an order on February 28, 2017, suspending that schedule and seeking comments on the proposed scope and schedule for this proceeding.

[1] On February 2, 2017, FERC issued an order (February 2 order) rejecting the Midcontinent Independent System Operator, Inc.'s (MISO) Competitive Retail Solution (CRS) tariff filing in Docket No. ER17-284-000. The FERC determined that the Forward Resource Auction proposed by MISO, which would apply to a small amount of load within MISO and would occur more than three years prior to MISO's existing Planning Resource Auction (PRA), would bifurcate the MISO capacity market and have potential adverse impacts on price. February 2, 2017 order, Docket No. ER17-284-000, p. 2. The FERC did not expressly comment on the Prevailing State Compensation Mechanism (PSCM) proposal that was set forth in MISO's CRS filing, however, the Commission understood that the PSCM was also rejected in the February 2 order, and concluded that further

Concluding that it must shift its focus from Section 6w(1) to 6w(8), on March 10, 2017, the Commission issued a scheduling order directing Consumers to, by April 11, 2017, file an application to implement a State Reliability Mechanism (SRM) charge, and setting dates for intervention and a prehearing conference.

On April 11, 2017, Consumers filed its application, along with supporting testimony and exhibits, for an SRM capacity charge under Section 6w of Act 341.

On April 25, 2017, Administrative Law Judge Mark D. Eyster (ALJ) held a prehearing conference, at which intervenor status was granted to the Association of Businesses Advocating Tariff Equity (ABATE), the Residential Customer Group, Sierra Club, Wal-Mart Stores East, LP, and Sam's East, Inc., Spartan Renewable Energy, Inc., Wolverine Power Marketing Cooperative, Inc. (Wolverine), Energy Michigan, Inc. (Energy Michigan), Calpine Energy Solutions, LLC, Constellation NewEnergy, Inc. (CNE), the Michigan Municipal Electric Association, Michigan State Utility Workers Council, Utility Workers Union of America, AFL-CIO, and the Michigan Department of the Attorney General (Attorney General). The Commission Staff (Staff) also participated. The ALJ set a schedule that provided for the Commission to read the record and issue an order no later than December 1, 2017, as required by Section 6w. *See*, January 20, 2017 order, p. 6.

On May 11, 2017, the Commission issued an order clarifying the procedure for establishing the format of the capacity demonstration process and seeking comments on three threshold issues.

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efforts to implement Section 6w(1) of Act 341 were no longer appropriate. Thus, the Commission turned its attention to implementation of a State Reliability Mechanism as required under Section 6w(2) of Act 341. March 10, 2017 order, p. 18.

On May 22, 2017, the ALJ granted the Michigan Chemistry Council's (MCC) request for late intervention, and on May 25, 2017, The Kroger Company (Kroger) filed a joint stipulation to permit intervention.

On June 1, 2017, the Staff filed a motion to strike certain testimony relating to the format for capacity demonstrations. On June 9, 2017, Consumers filed a response in opposition. On June 14, 2017, the ALJ held a hearing on the motion, and on June 28, 2017, he issued a ruling granting the motion, based on the March 10, May 11, and June 15, 2017 orders in this docket.

On June 8, 2017, the ALJ issued a Protective Order.

On June 15, 2017, the Commission issued an order in this docket and in Case No. U-18197 addressing threshold questions that had been put out for comment related to the capacity demonstration process.

On July 17, 2017, testimony and exhibits were filed by the Staff, Energy Michigan, ABATE, and CNE. On August 7, 2017, rebuttal testimony and exhibits were filed by Consumers, Kroger, ABATE, and Energy Michigan.

On July 26 and August 11, 2017, various parties filed motions to strike. At hearings held on August 2 and 16, 2017, the ALJ granted the motions in part. As a result, on August 23, 2017, Energy Michigan and ABATE filed revised testimony.

Evidentiary hearings were held on August 16 and 23, 2017. On September 26, 2017, initial briefs were filed by Consumers, the Staff, ABATE, the Attorney General, Kroger, Energy Michigan, CNE, and Wolverine. Also on that date, Consumers filed a motion to correct the transcript, the ALJ granted the motion, and the corrected transcript was filed. On October 12, 2017, reply briefs were filed by Consumers, the Staff, MCC, ABATE, CNE, Energy Michigan, and Wolverine.

The record consists of 805 pages of transcript and 66 exhibits admitted into evidence.

Background

MCL 460.6w(12)(h) defines the SRM[2] as "a plan adopted by the commission in the absence of a [PSCM] to ensure reliability of the electric grid in this state consistent with [MCL 460.6w(8)]."

Pertinent subsections of MCL 460.6w related to the capacity obligations and process are as follows:

> (2) . . . If, by September 30, 2017, the Federal Energy Regulatory Commission does not put into effect a resource adequacy tariff that includes a capacity forward auction or a prevailing state compensation mechanism, then the commission shall establish a state reliability mechanism under subsection (8). The commission may commence a proceeding before October 1 if the commission believes orderly administration would be enabled by doing so. If the commission implements a state reliability mechanism, it shall be for a minimum of 4 consecutive planning years beginning in the upcoming planning year. A state reliability charge must be established in the same manner as a capacity charge under subsection (3) and be determined consistent with subsection (8).
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> (3) After the effective date of the amendatory act that added section 6t, the commission shall establish a capacity charge as provided in this section. A determination of a capacity charge must be conducted as a contested case pursuant to chapter 4 of the administrative procedures act of 1969, 1969 PA 306, MCL 24.271 to 24.287, after providing interested persons with notice and a reasonable opportunity for a full and complete hearing and conclude by December 1 of each year. The commission shall allow intervention by interested persons, alternative electric suppliers, and customers of alternative electric suppliers and the utility under consideration. The commission shall provide notice to the public of the single capacity charge as determined for each territory. No new capacity charge is required to be paid before June 1, 2018. The capacity charge must be applied to alternative electric load that is not exempt as set forth under subsections (6) and (7). If the commission elects to implement a capacity forward auction for this state as set forth in subsection (1) or (2), then a capacity charge shall not apply beginning in the first year that the capacity forward auction for this state is effective. In order to ensure that noncapacity electric generation services are not included in the capacity charge, in determining the capacity charge, the commission shall do both of the following and

[2] The final sentence of Section 6w(2) refers to establishment of a "state reliability charge" in the same manner as a "capacity charge" under Section 6w(3). The remainder of Section 6w refers to the state reliability mechanism or SRM. "SRM charge" or "capacity charge" are used interchangeably throughout this order to refer to the state reliability charge.

ensure that the resulting capacity charge does not differ for full service load and alternative electric supplier load:

(a) For the applicable term of the capacity charge, include the capacity-related generation costs included in the utility’s base rates, surcharges, and power supply cost recovery factors, regardless of whether those costs result from utility ownership of the capacity resources or the purchase or lease of the capacity resource from a third party.

(b) For the applicable term of the capacity charge, subtract all non-capacity-related electric generation costs, including, but not limited to, costs previously set for recovery through net stranded cost recovery and securitization and the projected revenues, net of projected fuel costs, from all of the following:

(i) All energy market sales.

(ii) Off-system energy sales.

(iii) Ancillary services sales.

(iv) Energy sales under unit-specific bilateral contracts.

(4) The commission shall provide for a true-up mechanism that results in a utility charge or credit for the difference between the projected net revenues described in subsection (3) and the actual net revenues reflected in the capacity charge. The true-up shall be reflected in the capacity charge in the subsequent year. The methodology used to set the capacity charge shall be the same methodology used in the true-up for the applicable planning year.

(5) Not less than once every year, the commission shall review or amend the capacity charge in all subsequent rate cases, power supply cost recovery cases, or separate proceedings established for that purpose.

(6) A capacity charge shall not be assessed for any portion of capacity obligations for each planning year for which an alternative electric supplier can demonstrate that it can meet its capacity obligations through owned or contractual rights to any resource that the appropriate independent system operator allows to meet the capacity obligation of the electric provider. The preceding sentence shall not be applied in any way that conflicts with a federal resource adequacy tariff, when applicable. Any electric provider that has previously demonstrated that it can meet all or a portion of its capacity obligations shall give notice to the commission by September 1 of the year 4 years before the beginning of the applicable planning year if it does not expect to meet that capacity obligation and instead expects to pay a capacity charge. The capacity charge in the utility service territory must be paid for the portion of its load taking service from the alternative electric supplier not covered by capacity as set forth in this subsection during the period that any such capacity charge is effective.

(7) An electric provider shall provide capacity to meet the capacity obligation for the portion of that load taking service from an alternative electric supplier in the electric provider's service territory that is covered by the capacity charge during the period that any such capacity charge is effective. The alternative electric supplier has the obligation to provide capacity for the portion of the load for which the alternative electric supplier has demonstrated an ability to meet its capacity obligations. If an alternative electric supplier ceases to provide service for a portion or all of its load, it shall allow, at a cost no higher than the determined capacity charge, the assignment of any right to that capacity in the applicable planning year to whatever electric provider accepts that load.

(8) If a state reliability mechanism is required to be established under subsection (2), the commission shall do all of the following:

(a) Require, by December 1 of each year, that each electric utility demonstrate to the commission, in a format determined by the commission, that for the planning year beginning 4 years after the beginning of the current planning year, the electric utility owns or has contractual rights to sufficient capacity to meet its capacity obligations as set by the appropriate independent system operator, or commission, as applicable.

(b) Require, by the seventh business day of February each year, that each alternative electric supplier, cooperative electric utility, or municipally owned electric utility demonstrate to the commission, in a format determined by the commission, that for the planning year beginning 4 years after the beginning of the current planning year, the alternative electric supplier, cooperative electric utility, or municipally owned electric utility owns or has contractual rights to sufficient capacity to meet its capacity obligations as set by the appropriate independent system operator, or commission, as applicable. One or more municipally owned electric utilities may aggregate their capacity resources that are located in the same local resource zone to meet the requirements of this subdivision. One or more cooperative electric utilities may aggregate their capacity resources that are located in the same local resource zone to meet the requirements of this subdivision. A cooperative or municipally owned electric utility may meet the requirements of this subdivision through any resource, including a resource acquired through a capacity forward auction, that the appropriate independent system operator allows to qualify for meeting the local clearing requirement. A cooperative or municipally owned electric utility's payment of an auction price related to a capacity deficiency as part of a capacity forward auction conducted by the appropriate independent system operator does not by itself satisfy the resource adequacy requirements of this section unless the appropriate independent system operator can directly tie that provider's payment to a capacity resource that meets the requirements of this subsection. By the seventh business day of February in 2018, an alternative electric supplier shall demonstrate to the commission, in a format determined by the commission, that for the planning year beginning June 1, 2018, and the subsequent 3 planning years, the alternative electric supplier owns or has contractual rights to sufficient capacity to meet its capacity obligations as set by the appropriate independent system operator, or commission, as applicable. If the commission finds an electric provider has failed to demonstrate it can meet a portion or all of its capacity obligation, the commission shall do all of the following:

(i) For alternative electric load, require the payment of a capacity charge that is determined, assessed, and applied in the same manner as under subsection (3) for that portion of the load not covered as set forth in subsections (6) and (7). If a capacity charge is required to be paid under this subdivision in the planning year beginning June 1, 2018 or any of the 3 subsequent planning years, the capacity charge is applicable for each of those planning years.

(ii) For a cooperative or municipally owned electric utility, recommend to the attorney general that suit be brought consistent with the provisions of subsection (9) to require that procurement.

(iii) For an electric utility, require any audits and reporting as the commission considers necessary to determine if sufficient capacity is procured. If an electric utility fails to meet its capacity obligations, the commission may assess appropriate and reasonable fines, penalties, and customer refunds under this act.

(c) In order to determine the capacity obligations, request that the appropriate independent system operator provide technical assistance in determining the local clearing requirement and planning reserve margin requirement. If the appropriate independent system operator declines, or has not made a determination by October 1 of that year, the commission shall set any required local clearing requirement and planning reserve margin requirement, consistent with federal reliability requirements.

(d) In order to determine if resources put forward will meet such federal reliability requirements, request technical assistance from the appropriate independent system operator to assist with assessing resources to ensure that any resources will meet federal reliability requirements. If the technical assistance is rendered, the commission shall accept the appropriate independent system operator's determinations unless it finds adequate justification to deviate from the determinations related to the qualification of resources. If the appropriate independent system operator declines, or has not made a determination by February 28, the commission shall make those determinations. . . .

(12) As used in this section:

(a) "Appropriate independent system operator" means the Midcontinent Independent System Operator. . . .

> (c) “Electric provider” means any of the following:
> (i) Any person or entity that is regulated by the commission for the purpose of selling electricity to retail customers in this state.
> (ii) A municipally owned electric utility in this state.
> (iii) A cooperative electric utility in this state.
> (iv) An alternative electric supplier licensed under section 10a.
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> (d) “Local clearing requirement” means the amount of capacity resources required to be in the local resource zone in which the electric provider’s demand is served to ensure reliability in that zone as determined by the appropriate independent system operator for the local resource zone in which the electric provider's demand is served and by the commission under subsection (8).
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> (e) “Planning reserve margin requirement” means the amount of capacity equal to the forecasted coincident peak demand that occurs when the appropriate independent system operator footprint peak demand occurs plus a reserve margin that meets an acceptable loss of load expectation as set by the commission or the appropriate independent system operator under subsection (8). . . .
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> (h) “State reliability mechanism” means a plan adopted by the commission in the absence of a prevailing state compensation mechanism to ensure reliability of the electric grid in this state consistent with subsection (8).

Thus, Section 6w of Act 341 requires each electric utility, alternative electric supplier (AES), cooperative electric utility, and municipally-owned electric utility to demonstrate to the Commission, in a format determined by the Commission, that the load serving entity (LSE or electric provider) owns or has contractual rights to sufficient capacity to meet its capacity obligations as set by the appropriate independent system operator (ISO), or by the Commission, as applicable. In the event an AES cannot make the required capacity showing (or elects not to), Section 6w requires that an SRM capacity charge be assessed, to be determined by the Commission, with the associated capacity for such AES customers provided by the incumbent utility. Section 6w established a new framework for resource adequacy in Michigan – that is, ensuring electric providers can meet customers’ electricity needs over the long-term even during periods of high electricity consumption or when power plants or transmission lines unexpectedly go out of service. Act 341 went into effect on April 20, 2017.

Pursuant to a series of orders issued in Case No. U-18197 and the March 10, 2017 order in this matter, the Staff held a number of technical conferences for the purpose of addressing the procedures and requirements for demonstrating capacity. The Commission engaged stakeholders, with opportunities to provide comments and positions, and also opened dockets in this case and in Case Nos. U-18248, U-18253, U-18254, and U-18258, for the five electric providers with choice load potentially affected by the SRM charge requirement of Section 6w.

Under the Section 6w framework, the Commission must determine the capacity obligations for individual electric providers over a four year period and create a process to evaluate whether such obligations are met. Section 6w provides remedies in instances when an electric provider is unable to demonstrate it has procured adequate capacity to cover its load, including allowing for uncovered AES load to be assessed a capacity charge determined by the Commission and paid to the incumbent utility in exchange for meeting that load's capacity obligations. Special provisions exist for electric utilities, municipally-owned utilities, and electric cooperatives that fail to meet the Section 6w capacity obligations. Whether any capacity charge is actually imposed on choice customers will be determined after February 9, 2018, when AESs make their capacity demonstrations. However, under Section 6w(3), the capacity charge must be established by the Commission after a contested case by December 1 of each year, and the charge may not go into effect prior to June 1, 2018.[3]

[3] As the parties have noted, Consumers has a currently pending electric rate case, Case No. U-18322, that will conclude prior to June 1, 2018.

In the September 15, 2017 order in Case No. U-18197 (September 15 order), the Commission adopted a timeline and procedures for the capacity demonstration process referred to in Section 6w(6) and (8). In the September 15, 2017 order in Case No. U-18441, the Commission opened the docket that will be the repository for all of the electric providers' filings for the initial demonstrations for planning years 2018-2022. Under the approved timeline, the Staff will file a memo in that docket indicating its determination on each electric provider's demonstration by March 6, 2018. Show cause proceedings shall be initiated if an individual load serving entity does not appear to have sufficient capacity based on the Staff's assessment. Such a proceeding will provide an opportunity for parties to present evidence on whether the electric provider has failed to demonstrate that it can meet a portion or all of its capacity obligations, thereby triggering Commission action as set forth in Section 6w(8)(b)(i). The instant order will determine the capacity charge associated with load in Consumers' service territory. Whether the charge is levied on any retail open access customers will be determined by the outcome of any orders to show cause issued after March 6, 2018, for AESs operating in Consumers' service territory.

Positions of the Parties

Direct Testimony

Consumers Energy Company

David F. Ronk, Jr., Consumers' Executive Director of Transaction and Wholesale Settlements in the Energy Supply Operations Department, provided an overview of how Consumers proposes to implement the SRM charge. He began by describing the statute. Mr. Ronk testified that under Section 6w incumbent utilities may be required to provide capacity for the load of retail open access (ROA or choice)[4] customers that is not satisfied by their respective AES in the required forward resource adequacy demonstration, and that the Commission is required to conduct a contested case to set the capacity charge that will be paid to the incumbent utility in that situation. He testified that the initial SRM charge must be in effect for a minimum of four consecutive planning years beginning June 1, 2018, but he recommends that the Commission set a term of an indefinite length, so that the SRM itself is permanent until directed otherwise by the Legislature. He offered two reasons – first, that grid reliability should not be artificially limited, and second, that utilities need to plan the construction of new generation facilities over the long-term, and need the assurance that the charge will remain in effect for planning purposes.

Mr. Ronk testified that, if an AES fails to make its capacity demonstration by February 9, 2018, then the capacity charge must be assessed to that AES's uncovered retail electric load for each of the four planning years from June 1, 2018 through May 31, 2022 (a planning year runs from June 1 through May 31). He stated that, beginning with the seventh business day of February 2019, the Commission should establish a term for the charge "of a length sufficient to prevent AESs and ROA customers from having the opportunity to game the utility's capacity resources by relying on the utility to provide capacity for periods of up to four years, then returning to AES-provided capacity service, all while having the assurance of being able to return to the utility's capacity service in the event that the AES is unable or unwilling to provide capacity to its retail customers." 5 Tr 238-239. He suggested that a 30-year term is appropriate. The term would begin when the ROA customer first becomes subject to the charge and end 30-years from that date, at which point a new 30-year charge could go into effect.

[4] These terms are used interchangeably throughout this order.

Mr. Ronk indicated that Consumers is unable, through its billing and accounting system, to allocate the capacity charge on a pro rata basis to each ROA customer, and so the charge must be allocated to individual customers on a first-in/last-out basis. For example, he indicated, if an AES with five customers can only meet four-fifths of its capacity obligation, Consumers does not have the ability to bill one-fifth of the capacity charge to each customer; instead, the fifth customer to enroll with the AES will pay the full capacity charge and the other four customers will pay no capacity charge.

With regard to any capacity obligation assigned to Consumers, Mr. Ronk stated that the utility will pursue the best option for each planning year, which could include new power purchase agreements (PPAs), energy optimization (EO), demand response (DR), new generation construction, or use of the MISO PRA; but he emphasizes that in the short run, due to the fact that a new capacity obligation could accrue as soon as June 1, 2018, Consumers is likely to rely on the PRA.

Mr. Ronk noted that an AES that makes its initial demonstration but later determines that it will not meet the capacity obligation in a subsequent planning year, must provide notice to the Commission by September 1 of the year fours before that planning year under Section 6w(6). For example, if an AES decides that it will no longer be able to make its demonstration for the 2025/2026 planning year, it must notify the Commission no later than September 1, 2020, and the affected utility must then account for that additional capacity by December 1, 2020. In the converse situation, where a capacity charge has been imposed but the AES is subsequently able to make its demonstration, Mr. Ronk stated that the charge must remain in effect until the initial 30-year term has expired based on the language of Section 6w(6). He claimed that any shorter term would allow the ROA customer to "game" the utility's capacity resources and jeopardize the grid.

He posited that ROA customers should not be subject to an on-again off-again charge, and that the utility will not want to obtain long-term capacity to serve load that might disappear in less than 30 years. Mr. Ronk suggested that the Commission could amend the ROA tariff to provide that the customer may either be subject to the charge for 30 years or return to bundled service.

Further, Mr. Ronk explained that, once the charge is in place, an ROA customer's energy consumption must continue to count towards the 10% choice cap for the duration of the 30-years, even if the customer returns to full service. He averred that space under the cap could be created only if an AES has no capacity charge in place. He reasoned that a utility could find itself "long in capacity" if an ROA customer subject to the charge returns to full service, and is replaced by a new ROA customer for whom the AES demonstrates satisfactory capacity. 5 Tr 248.

Finally, Mr. Ronk addressed the true-up mechanism and the categories of possible net revenue reductions set forth in Section 6w(3)(b). He indicated that Consumers has no energy market sales because on a net annual basis it is a purchaser of energy; no off-system energy sales because its only off-system sales are to Alpena Power Company (Alpena) and are not profitable; no ancillary service sales because on an annual basis Consumers is a net buyer of ancillary services; and no energy sales under unit-specific bilateral contracts. He posited that the Commission should undertake the annual true-up through a combination of the power supply cost recovery (PSCR) process, the general rate case process, and an annual stand-alone case process that has not yet been established. He offered a schedule for the annual SRM charge review case under Section 6w(5), wherein every March 15 utilities would file a new charge calculation for review, the Commission would issue an order by May 1, and the new charge would be implemented on June 1. He suggested that, going forward, every March 15 each utility can update the costs that are included in the calculation of the charge based on changes to base rate capacity costs and PSCR cases which will have been litigated in those separate cases. He maintained that this would be preferable to updating the SRM charge on an annual basis through a rate case or PSCR case. He noted that the PSCR factor will be separated into capacity and non-capacity components.

Sara T. Walz, a Senior Engineering Technical Analyst in Consumers' Energy Supply Operations Department, addressed forecasted PSCR expenses for 2018. Exhibit A-15. She testified that PSCR costs were allocated between capacity and non-capacity costs as follows:

> Certain expenses represent the cost of capacity in the form of Zonal Resource Credits purchased through bi-lateral agreements or expected to be purchased in MISO's Planning Resource Auction in late March 2017 and late March 2018. For purchases already made, the actual price paid is allocated to each month for which the purchase applies. For future purchases, an estimated auction clearing price is based on a Company-generated forecast of capacity value.

5 Tr 391-392. She testified that Consumers anticipates incurring approximately $1.968 billion in PSCR expense during 2018, and that 26% of that amount is expected to be incurred for fixed or capacity-related expenses.

Josnelly C. Aponte, Principle Rate Analyst in Consumers' Rates and Regulation Department, presented the company's electric cost of service study (COSS) by rate class for calculation of the capacity charge. She explained that, where possible, the COSS assigns individual costs that can be traced to a rate class to that rate class. Exhibit A-1 summarizes the COSS approved in the February 28, 2017 order in Case No. U-17990, Consumers' most recent electric rate case, which relies on a 4 CP 75/0/25 weighting method for production capacity and a 12 CP 100 method for transmission expense. She explained that Exhibit A-2 is the COSS used for rate design in this proceeding, which begins with the rate case COSS but includes a new classification of the production revenue requirement to comply with implementation of the SRM charge. Ms. Aponte stated that the company identified the capacity related generation costs included in base rates, and separated out transmission and critical summer peak energy costs as non-capacity related. The capacity related costs were determined "by identifying the non-capacity related costs and subtracting them from the total production related costs." 5 Tr 347. Like Mr. Ronk, she stated that Consumers does not have any projected net revenues from energy sales.

Laura M. Collins, Principle Rate Analyst – Lead in Consumers' Rates and Regulation Department, addressed how the utility's current rates would be modified to implement the SRM charge. To begin with, she explained that the company proposes that the AES be responsible for notifying Consumers of which ROA customers would be subject to the capacity charge. Ms. Collins stated that, after costs were separated into capacity and non-capacity costs, she designed a rate for each rate class that collects the allocated capacity costs based on the customers' sales determinants. She stated that her design ensures that any ROA customer subject to the charge pays the same as a comparable full service customer. She testified further that for rates that have power supply demand charges, 100% of the capacity costs are being collected in the power supply demand charges while non-capacity costs are being collected in per kilowatt-hour (kWh) volumetric charges. Exhibit A-4 provides a summary of revenues by rate and service type (bundled or ROA). She stated that for purposes of this case Consumers is assuming that no ROA customers are subject to the capacity charge, and that if the company had projected any ROA customers to be subject to the charge, the rates would change based on the fact that the SRM charge for each customer class would change. She explained:

> [W]ithout knowing exactly how much ROA load the Company would be responsible for providing capacity for, it would be impossible for the Company to establish a rate that collects the precise amount of capacity costs. In the future, the SRM capacity charge would be updated as a result of the Company's general rate cases, where changes to capacity rate base are updated; PSCR cases, where the Company's purchased capacity costs are reconciled; or in the annual Commission review and amendment of the SRM capacity charge. In the course of these proceedings, the Company's capacity costs, as well as the amount of Full Service and ROA load for which the Company provides capacity, may be updated.

5 Tr 376-377. Consumers proposes that net revenues related to net energy sales be reconciled in the annual PSCR reconciliation. Ms. Collins indicated that Consumers will separate the PSCR costs such that adjustments to the PSCR factor related to purchased capacity can be identified, and ROA customers who are subject to the SRM charge will be responsible for the portion of the monthly factor that is associated with purchased generation capacity just as full service customers are.

Ms. Collins presented proposed tariff sheets in Exhibit A-9. She explained that Consumers proposes a change to the ROA tariffs concerning a customer's return to full service, to provide that if an ROA customer returns to full service as a result of an AES's inability to provide capacity for that customer, then the ROA cap shall not be backfilled by that amount of load for the period that remains on that customer's obligation to pay the capacity charge. In other words, that customer's load would continue to count toward the 10% cap on ROA for the remainder of the 30-years proposed by Consumers.

The Commission Staff

Eric W. Stocking, an Economic Specialist in the Commission's Financial Analysis and Audit Division (FAAD), testified that, consistent with Section 6w(2), the SRM should be in effect in perpetuity, or until Act 341 is revised, because the SRM provides the Commission with a tool to ensure the long-term reliability of the grid and provides an economic incentive to LSEs to plan for future capacity obligations. He explained that the term of the SRM is different from the term of any capacity charge established for AES load. He testified that Consumers' proposal to keep the charge in place for a minimum of 30 years conflicts with the plain language of Section 6w(6) which states that a "charge shall not be assessed" for any portion of the capacity obligation for a planning year which the AES demonstrates an ability to meet. Mr. Stocking maintained that the capacity charge may only be assessed for AES load (for any planning year) for which the AES was unable to demonstrate an ability to meet. "For the years where an AES is able to demonstrate that it owns or contracted for sufficient resources to satisfy its capacity obligations, no capacity charge should be levied onto that particular AES's customers." 6 Tr 738-739.

Mr. Stocking opined that, under Section 6w(8)(B)(i), in the initial four year period beginning June 1, 2018, any portion of AES load that is not supported by a satisfactory capacity demonstration in any one of those first four planning years would be subject to the charge for those four years, and that, beginning with planning year five and thereafter the AES may make the demonstration on an annual basis and customers would be subject to the charge on an annual basis as well. Mr. Stocking indicated that the Staff generally agrees with Consumers that the utility may have no other choice but to procure resources from the PRA in the short term, and noted that this would be no different from how the affected AES would have procured the capacity.

Mr. Stocking testified that the Staff disagrees with Consumers' proposal to subject only certain ROA customers to the charge. He stated that resource planning and acquisition are typically done on an aggregate basis and that it is the responsibility of each LSE to procure adequate capacity to meet its obligations. He noted that the utility does not indicate which customers it has purchased capacity for.

Heather A. Cantin, Department Analyst in FAAD, testified that Consumers' proposal to change the ROA tariff to prevent backfilling of the load of a returning customer conflicts with MCL 460.10a(1)(i) and existing Commission orders, which require the utility to award allotments from the existing ROA queue until the available energy allotments are exhausted or the queue to empty. *See,* April 28, 2017 order in Case No. U-15801, App. A. She pointed out that Consumers' proposal would prohibit the customer at the top of the queue from taking choice service and opined that the “fact that the existing ROA customer was subject to the SRM should not change how the queue works.” 6 Tr 727. Ms. Cantin contended that available space in the choice program should be filled, and noted that, if this process were adopted, eventually the utility’s cap would be reduced below 10%. Addressing whether the utility may end up with extra capacity, she stated “If the Company is long on capacity, it could then evaluate whether to retain the extra capacity, sell some extra capacity, or investigate retiring facilities that may no longer be needed as part of its normal resource planning activities. The extra capacity is not wasted.” 6 Tr 729.

Finally, Ms. Cantin testified that the Staff disagrees with Consumers’ proposed tariff language creating a 30-year obligation to pay the capacity charge, and she proposed alternative language indicating that only the first four planning years create a multiyear obligation period.

Nicholas M. Revere, Manager of the Rates and Tariff Section of the Commission’s Regulated Energy Division, presented the Staff’s calculation of the capacity charge. He opined that the appropriate cost of capacity is the cost of new entry (CONE), or the cost to build a combustion turbine (CT). He testified that Consumers identified energy related costs, and considered all other costs capacity related, but opined that this method is incorrect because not all costs that are not energy related are capacity related. The Staff, on the other hand, went through the COSS and identified costs that are capacity related, and then considered all other costs non-capacity costs. Exhibit S-1.1.

Mr. Revere stated that the Staff identified all costs currently allocated using the production cost allocator (with the exception of fuel handling costs) as potentially capacity related. He indicated that the current production cost allocator of 4 CP 75/25 recognizes that 75% of costs are capacity related. He goes on to state:

> An alternative methodology, as mentioned previously, is to identify all costs allocated by the former allocator, and set the percentage applied to determine which of those

> costs are capacity-related at the percentage necessary to make the resulting amount equal to CONE or some other measure of the value of capacity, as determined by the Commission. This would treat all costs in excess of CONE (or the Commission's chosen value of capacity) as non-capacity-related costs. Should the Commission determine such a method is more appropriate, Staff recommends that the levelized per year cost of a CT resulting from the Company's [Public Utilities Regulatory Policy Act of 1978] PURPA case, U-18090, be utilized.

6 Tr 755. Mr. Revere indicated that revenue recorded in the intersystem sales account should be included as capacity related because Section 6w(3)(b) expressly requires the inclusion of "all energy market sales" revenue as an offset to the cost of capacity.

Mr. Revere stated that the Staff agrees with Consumers that Section 6w requires a single capacity charge applied to similarly situated ROA and full service customers, allowing for collection of class cost responsibility from that class. With respect to the issue of how to align the collection of costs with customers' contributions to the need for capacity if a single identical charge is required by the Commission, he noted two difficulties. First, he stated that billing according to the measure of contribution is effectively impossible because demand and energy are averaged over a number of years. Second, customers would not be able to determine when the peak hours would occur because they are not known until after the fact. He suggested using a proxy such as on-peak demand, or "isolating some number of hours likely to become the CP and charging each of those hours at the same rate." 6 Tr 759. He opined that for classes with large numbers of diverse customers, on-peak summer kWh is the best starting point. In sum, he recommended that capacity related costs be collected through summer on-peak kWh charges for rate schedules without demand charges, and through summer on-peak kilowatt (kW) charges for rate schedules with demand charges. Exhibits S-1.2, 1.3, and 1.4. If the Commission decides that all customers must pay the same charge, then he recommends that the charge be collected through a uniform summer on-peak kWh charge. Exhibits S-1.5, 1.6, and 1.7.

Mr. Revere stated that Section 6w(3)(b) requires only a very limited reconciliation of the projected net revenues used in the calculation of the SRM charge to the actual net revenues, and the difference is reflected in the charge for the next year. He noted that capacity related costs associated with PPAs are reconciled as part of the PSCR process, and disagreed with Consumers' proposal to split the PSCR factor into capacity and non-capacity components, stating:

> PSCR-related rates are split into two pieces: (1) the base, which is included in regular rates, and (2) the factor, which is intended to effectively increase or decrease the base throughout the year in order to minimize the over or under collection at the end of the year. The billed factor is set at the Company's discretion, subject to a cap. It is basically impossible to identify what costs are included in the base as opposed to the factor. Consequently, the best way to deal with potential mismatches between the amount of capacity-related costs incurred in a given year and the amount collected through the Capacity Charge is in the PSCR Reconciliation process. It would be reasonable to assume that the amount of Capacity Charge revenue associated with PPA capacity costs is proportionate to the amount of PPA capacity costs included as part of the calculation of the Capacity Charge. For example, if PPA Capacity costs are 5% of the total capacity-related costs used to calculate the Capacity Charge, 5% of the revenues received from that charge should be considered revenues to cover those same costs. Any difference between the collected revenue so calculated and the actual PPA capacity costs should be included in the calculation of the next year's Capacity Charge. This is the same treatment required for the net revenue reconciliation, and keeps the Company whole in the same manner the current PSCR reconciliation does.

6 Tr 761-762.

Finally, Mr. Revere took issue with Consumers' claim that its billing system does not allow for the proration of capacity charges. He pointed out that Consumers prorates charges on a regular basis, and gave examples.

<u>ABATE</u>

James R. Dauphinais, Managing Principle at Brubaker & Associates, Inc., appeared on behalf of ABATE, noting that its members include both bundled and ROA customers. Mr. Dauphinais began by describing the role of MISO with respect to capacity decisions, and noted that a zonal resource credit (ZRC) does not provide its owner with any right to directly receive energy from the source of the ZRC, but instead places an obligation on the source to offer energy into MISO. He testified that MISO does not place geographic limitations on individual LSEs unless the LSE chooses to use a Fixed Resource Adequacy Plan (FRAP). He noted that the MISO footprint is broken up into Local Resource Zones (LRZ), and MISO imposes a Local Clearing Requirement (LCR) on each zone when it runs its annual PRA. He described other transmission limitations such as the Capacity Import Limit (CIL), but stated that the LCR is the most important limit with respect to the SRM in LRZ 7, which encompasses the portion of MISO in the lower peninsula of Michigan. Mr. Dauphinais explained that if an LSE uses a FRAP, it may not specify ZRCs located outside of the zone of its Planning Reserve Margin Requirement (PRMR) in excess of its load ratio share of the effective import capability into that zone. He opined that the SRM charge should exclude utility generation costs that are not associated with providing ZRCs.

Mr. Dauphinais articulated several concerns with Consumers' method for developing its proposed capacity charge. Noting that ZRCs provide no energy to AESs or choice customers, he testified that Consumers inappropriately classifies the 25% of total energy usage allocation of fixed production costs as capacity related, when they are better characterized as non-capacity. Exhibit AB-2. He indicated that it is unreasonable for Consumers to assume that no ROA customers will pay the charge, because it will result in Consumers collecting well in excess of the incremental cost to provide capacity to ROA customers when the charge comes into play – 115.7% annual excess by his calculation (using CONE). Mr. Dauphinais recommended that the Commission require Consumers to file an updated capacity charge after the February 2018 AES SRM demonstrations are made and Consumers' pending electric rate case, Case No. U-18322, is final. He stated that the filing should reflect actual billing units and incremental costs. He also averred that Consumers should not recover non-capacity costs on a per kWh basis for rate classes that currently have a power supply demand charge, because it unreasonably allocates transmission expense between customers in those rate classes, and because non-capacity costs are not necessarily all energy related. He recommended a demand rate charge for both the SRM charge and the PSCR factor, and that transmission expense should be recovered through a non-capacity demand charge.

Mr. Dauphinais offered that perpetual implementation of the SRM is unnecessary because the act requires implementation on an annual basis once the initial four years has expired. He called Consumers' 30-year proposal highly anticompetitive. He also characterized the lowering of the choice cap and the use of a first-in/last-out method for identifying target customers unreasonable and anticompetitive. Finally, he recommended that any capacity charge for local capacity provided to ROA customers be charged separately as a Local SRM Capacity Charge, based on the revenue requirement for the incremental local capacity. "Therefore, to the extent this incremental local capacity proposal is adopted by the Commission in Case No. U-18197, Consumers' SRM Capacity Charge set in this proceeding should not apply to the provision of such incremental local capacity from Consumers to its bundled retail and ROA customers." 6 Tr 540.[5]

Constellation NewEnergy

Jeff D. Makholm, Ph.D., Senior Vice President/Managing Director of National Economic Research Associates, Inc., testified that the law now requires incumbent regulated utilities to include the 10% choice customers in their capacity plans, and described the capacity charge as new and incremental for ROA customers. He stated that, had Consumers used a planning model, it "could have calculated an SRM charge that reflects its going-forward capacity-only costs during

[5] In the September 15 order, the Commission delayed implementation of the locational requirement for the first four planning years.

the applicable term of the capacity charge." 5 Tr 416. He described Consumers' method of computing the charge based on the split between its fixed and variable embedded costs of service as more advantageous for the utility than using incremental or marginal costs. He posited that Consumers overstates its capacity charge by failing to account for the fact that ROA customers place no energy demands on Consumers' system even though energy remains a major determinant of production plant costs.

Dr. Makholm noted that Consumers did not directly identify capacity costs in its calculation, but rather classified all costs not included as non-capacity as capacity costs. He opined that this method does not comport with the intent of the legislation:

> Such a method only serves roughly to segregate fixed costs from variable costs. It does not reflect, and has no practical possibility of finding, an SRM capacity charge that deals reasonably with the problem that Section 6w seeks to remedy—which is to establish a "cost-effective, reasonable and prudent" mechanism to ensure reliability. The legislation seeks to ensure sufficient capacity resources at the "forecasted coincident peak demand" plus a reserve margin. In contrast, Consumers' proposed "capacity charge" is made up of the entirety of its non-variable costs unrelated to any measure of peak reliability, as such. Consumers' charge is not related to "capacity" in any way consistent with what the legislation appears to be seeking. Consumers' method is simply a fixed cost-related charge that does not recognize that many of Consumers' fixed embedded costs are related to providing energy—a service that AES customers do not receive from Consumers.

5 Tr 419. He opined that Consumers' method cannot be reconciled with the language of the statute that requires that non-capacity services not be included in the charge, and that the SRM be cost-effective, reasonable, and prudent. He averred that the incremental cost should be calculated, and should be easy to calculate as simply the increase in peak load with no corresponding energy; he provided an example that would require Consumers to adjust planning model software to increase the reserve margins to include the expected AES demand, and to run it once more with the reserve margin set at zero. Dr. Makholm testified that Consumers' approach of dividing up the embedded cost of service is not forward-looking or economically efficient, nor does it actually

reflect the cost of “the incremental facilities needed to meet the projected coincident peak load as opposed to those that only provide energy.” 5 Tr 426. He recommended the use of a planning model.

Dr. Makholm testified that Consumers’ proposal results in a capacity charge of $511 per megawatt-day (MW-day), which he characterized as unreasonable because it is simply the traditional revenue requirement minus “non-capacity related” expenses and lacks either a planning element or an objective standard for reference – it would just charge AESs a pro rata share of the utility’s historical revenue requirement. He applied the average and excess energy weighting method to calculate a capacity charge of $255/MW-day. As a check, he examined CONE for 2016 which was $260/MW-day, and noted that in Case No. U-18250 Consumers supported an estimate of market capacity value of 50% of CONE. He also examined the cost of ZRCs resulting from a recent Request for Proposals issued by Consumers in Case No. U-18382, and noted that the utility picked offers at or below $164/MW-day. Thus, he concluded that Consumers’ proposed amount is unreasonable. Finally, Dr. Makholm testified that the 30-year term is also unreasonable because it is based on the unsupported assumption that the utility will build power plants. He posited that Consumers’ own actions and evidence in Case Nos. U-18382 and U-18250 belie the alleged reliance on new power plants.

<u>Energy Michigan</u>

Alexander J. Zakem, an independent consultant, testified that the language of Section 6w does not indicate an understanding of current MISO reliability procedures, because it seems to assume that the LSE’s capacity obligation is satisfied by ownership of physical capacity, when in fact it is simply satisfied by money, noting that LSEs do not take title to ZRCs in the PRA nor are ZRCs assigned to specific LSEs – rather, MISO uses all resources to serve all load. Mr. Zakem explained that it is not clear how the Commission will harmonize Section 6w with MCL 460.11(1) which requires electric rates to be based on the cost of service. He further asserted that, under the MISO tariff, Consumers cannot reassign forecast load or PRMR from one LSE to another (including from an AES to a utility). He posited that application of an SRM charge to LSEs in the wholesale market such as AESs, municipal utilities, and cooperatives "raises jurisdictional issues involving wholesale versus retail authority." 6 Tr 629.

Mr. Zakem testified that the capacity charge should be forward looking, and based on the incremental costs Consumers would actually incur if providing capacity, noting that the cost of acquiring additional capacity is forward looking and not based on historical investments or fixed costs. He posited that this type of calculation would comport with cost of service principles. He noted that Consumers cannot remove a MISO PRMR obligation from an LSE, and stated that Consumers' 30-year proposal does not constitute just and reasonable ratemaking. He noted that choice customers do not contribute to monthly summer peak demand and thus the 75% of production costs should not be allocated to them based on-peak demand.

Mr. Zakem proposed that the cost of new replacement capacity resources should be shared by all LSEs in Consumers' distribution area, as long as they are qualified as ZRCs by MISO, including new builds, new DR, and new EO, approved by the Commission through the certificate of necessity process. The capacity cost alone would be shared and fair compensation for the value of the qualified new resource would be CONE, or the difference between the auction clearing price (ACP) and CONE, with apportionment pro rata on the basis of relative PRMR. He posited that his alternative charge calculation eliminates the need for any minimum term. He also noted that there "could be an argument that 4 years of any state-imposed obligation conflicts with the federal tariff, since MISO only has a one-year prompt planning year." 6 Tr 669.

Lael E. Campbell, Director of Regulatory Affairs for Exelon, testified that AESs do not designate specific resources to serve specific customers. He noted that Section 6w(6) states that the capacity charge is paid “for the portion of load” taking service from the AES. He had the following criticisms for Consumers’ proposal:

> Eliminating the ability for the AES to manage the customer’s capacity as part of a larger portfolio of resources and customers would be inconsistent with the MISO tariff and will only serve to increase costs on customers subject to the SRM. It would also create an additional competitive disadvantage for AESs compared to the utilities, who have and will continue to serve their aggregate load through a combined portfolio of generation resources. . . . Placing the SRM charge directly on the customers will place the customer at the center of disputes related to the AES’s demonstration of capacity. Such disputes would be better managed by the AES and the Company as those two entities would be more knowledgeable of the capacity demonstration and SRM process. Allowing AESs to manage the SRM charge on a portfolio level puts AESs on equal footing with the utilities, who spread capacity costs across their customer portfolio.

6 Tr 714-715. He recommended that the charge be assessed on a portfolio basis, because that is consistent with utility and MISO practice. He also recommended that the charge be assessed to the AES rather than the individual customer so that the AES can manage capacity; and, in order to avoid double billing, he averred that the AES should be billed in an amount equal to the SRM minus the ACP for the applicable delivery year.

Rob Jennings, Senior Consultant with Energy Ventures Analysis, Inc., testified that Consumers participates in MISO and offers its output to MISO, which dispatches the plants economically through the use of the AURORAxmp hourly dispatch model (Aurora). He described his inputs to Aurora and assumptions he used to forecast Consumers’ total fuel cost, off-system power sales, ancillary service sales, and bilateral sales for 2018 through 2021. Exhibits EM-12, EM-13, EM-14, and EM-15. Mr. Jennings stated that he developed assumptions based on Consumers’ most recent PSCR plan (Case No. U-18142), Consumers’ list of long-term electric purchase contracts, and data provided by Consumers in Case No. U-18250. He also calculated the five-year historical average of off-system power sales to Alpena as reported in information provided by Consumers to FERC. With regard to ancillary services, he noted that the word "net" does not appear in the statute and concludes that ancillary services should be quantified regardless of profitability. He forecasted no bilateral sales for the time period.

Ralph C. Smith, senior regulatory consultant with Larkin & Associates, PLLC, testified regarding how the SRM charge should be computed if the Commission chooses to use the traditional embedded cost method for doing so. He noted that currently CONE in LRZ 7 is $94,900 per MW per year. He identified Consumers' total capacity cost of $1.565 billion from this record, and noted that Consumers applied the 75-0-25 production cost allocator in this case. Using the forecasted offset amount arrived at by Mr. Jennings of $651 million for 2018, he determined that Consumers' net capacity cost is $914 million. Exhibit EM-7. He noted that Consumers has a total of owned and purchased capacity of 8,331 MW. He divided the capacity cost by the capacity to produce a cost of $109,714 per MW-year, or about $300 per MW-day. *Id.* He posited that a rate developed by rate class is not necessary when using embedded costs. However, he noted that Energy Michigan does not recommend-use of the embedded cost approach.

<u>Rebuttal Testimony</u>

<u>The Kroger Company</u>

Neal Townsend, Principal at Energy Strategies, LLC, testifies on behalf of Kroger to rebut the Staff and ABATE. He indicates that Kroger operates more than 20 facilities in Consumers' territory, mostly under Rate GPD. Mr. Townsend testifies that Mr. Revere's proposal for collection through summer on-peak charges "distorts the relationship between power supply demand charges and energy charges and is inconsistent with the nature of the underlying costs." 5

Tr 401. He posits that a number of costs should be functionalized to the demand related production function, including general, common and intangible plant, administrative and general expense, and payroll related taxes, because they are not energy related. Otherwise, he explains, customers with high average load factors will be over-burdened with power supply costs.

Mr. Townsend also describes the Staff's proposal to collect the entirety of capacity related costs from demand billed customers in the summer on-peak demand charge as a "radical change in rate design." 5 Tr 403. He states that currently these costs are recovered through the demand charge on a year-round basis, and the Staff's proposal will dramatically increase summer bills for bundled customers, causing cash flow spikes. He posits that the capacity charge should recover costs throughout the year, and notes that Consumers and ABATE propose a year-round charge. He also proposes that transmission expense be recovered through a non-capacity demand charge from demand billed customers.

<u>ABATE</u>

Mr. Dauphinais testifies on behalf of ABATE to rebut the Staff, CNE, and Energy Michigan. He disagrees that Consumers' fixed production costs in excess of the CONE of a CT generator are all energy related costs, arguing that legacy costs (such as past poor investments and generational differences in the cost of construction of new generation capacity) are not energy related and should be allocated to bundled customers on the basis of coincident peak demand rather than energy consumption. He also disagrees with CNE's use of the average and excess cost allocation method.

Mr. Dauphinais avers that the Staff's proposed charge significantly shifts revenue collection amongst Rate GPD customers outside of a rate case, and posits that compliance with Section 6w does not require reallocation of revenue recovery among bundled service customer classes. He opposes the Staff's rate design. He states that his Exhibit AB-5 compares the Staff's proposed revenue requirement allocation by class to the current allocation scheme approved in Case No. U-17990, and shows a $16 million shift among Rate GPD voltage level classes. He claims that Section 6w does not require this kind of reallocation. He supports the Staff's proposal with respect to reconciliations. He opposes, however, the Staff's summer on-peak kWh based rate design, arguing that it is contrary to industry standards and violates the cost based principles of MCL 460.11.

Energy Michigan

Mr. Zakem testifies on behalf of Energy Michigan to address the issue of "how the subtractions for all energy market sales and other sales specified in [Section 6w(3)(b)] should be included in the proposed SRM charges of the" Staff, Consumers, ABATE, and CNE. 6 Tr 673. He states that if the capacity costs are determined by a method other than via embedded costs, then the subtraction of the various sales is not needed, but that the listed parties all used embedded costs (for at least one of their proposals, noting that the Staff and CNE also offer alternatives). He also states that the capacity charge must be determined in light of the cost based requirement of MCL 460.11(1).

Mr. Zakem testifies that "Since all the output of all generation is sold to the MISO energy market, and all energy delivered to LSEs is bought from the MISO energy market, face-value interpretation of 'all energy market sales' means all energy sales, not energy sales less energy purchases." 6 Tr 676. He believes that Consumers is incorrect to net MISO sales against MISO purchases for purposes of Section 6w(3)(a) and (b). He supports Mr. Jennings' projections which found that the subtraction under subparagraph (b) is valued at $651 million for 2018, which consists of total sales revenue of $1,060 million less total fuel cost of $409 million. Exhibits EM-

14 and EM-15. He also disagrees with how the Staff performed the calculation, arguing that the subtraction should have included all energy market sales, not the portion of energy above the amount used by customers. He makes the same suggestion with regard to the proposals of Consumers, ABATE, and CNE.

<u>Consumers</u>

Ms. Collins testifies on behalf of Consumers to rebut the Staff, ABATE, and CNE on the issue of rate design. She notes that full service customers pay for capacity year round, not just in the summer; and capacity service is provided year round, thus she disagrees with Mr. Revere's collection proposal. She also offers that "The proration Mr. Revere is suggesting would be customer specific based on the AES serving the ROA customer. It is possible that our billing system could be configured to accommodate this type of proration, but such configuration does not exist in the system today and would take time and resources to make such a configuration operational." 5 Tr 384. She further suggests that the PSCR factor be adjusted monthly to reflect incremental changes in capacity as they occur. She disagrees with Mr. Makholm's use of the average and excess method because full service customers do not currently pay for capacity based on that method. Finally, she disagrees with Mr. Dauphinais' proposals for a demand charge for recovery of transmission costs and for an update to the charge after the February 2018 AES demonstrations, arguing that such changes should be addressed in a rate case. Likewise, she avers that approval for a different PSCR factor for each rate class would need to occur in a PSCR plan case.

Ms. Aponte testifies to rebut the Staff, CNE, ABATE, and Energy Michigan on issues related to the COSS. She emphasizes that Section 6w(3)(a) requires the calculation to "include the capacity related generation costs included in the utility's base rates," and states that the company followed the principles laid out in the National Association of Regulatory Utility Commissioners Electric Cost Allocation Manual (NARUC Manual) with regard to the functionalization and classification of production costs. In focusing on the 75% demand allocation, she contends that the Staff ignored other capacity related costs such as intangible plant, and other joint and common costs based on labor ratios or plant-in-service. Ms. Aponte states that there are costs within the other 25% that should be included because they are not energy related. She rebuts Mr. Dauphinais and Mr. Zakem with the same argument. She notes that any costs related to stranded costs and securitizations were not included as capacity related costs.

Ms. Aponte explains that Consumers' calculation method followed the method approved by the Commission for Indiana & Michigan Power Company's (I&M) state compensation mechanism (SCM) capacity charge in Case No. U-17032, another charge that was intended to apply to ROA customers for capacity.[6] She notes that the Staff supported I&M's method for calculating capacity and non-capacity production costs in that case, and it was approved by the Commission in the September 25, 2012 order in Case No. U-17032. She argues that the Staff's method in this case is inconsistent with the method approved in that order. Ms. Aponte also disputes Mr. Revere's alternative proposal based on the CONE for a CT facility because it encompasses only incremental capacity and not the utility's entire portfolio.

Ms. Aponte again refers to the language of Section 6w(3)(a) to rebut Mr. Makholm's assertion that the charge should be forward looking. She also disputes his use of the average and excess methodology because a change to the production allocation can only occur in a rate case, and because any attempt to calculate a charge for choice customers differently from how it is

[6] I&M has an SCM (rather than an SRM) because it is located in PJM Interconnection LLC's (PJM) ISO territory.

calculated for bundled customers would not comply with Section 6w(3) which requires that the "charge does not differ for full service load and [AES] load."

Mr. Ronk testifies to rebut each Staff and intervenor witness on most of the issues. He begins by asserting that Section 6w is not simply intended to safeguard reliability in the state, but also serves to ensure that both bundled and ROA customers pay the same rate for capacity at the time the utility provides capacity on their behalf. He reminds the Commission that Consumers' entire fleet of capacity resources is used holistically, and existing resources should be included in the determination of the SRM charge; otherwise bundled customers will continue to pay for baseload units, while choice customers would pay for only the incremental capacity associated with peaking plants.

Mr. Ronk notes that Michigan has a well-established policy of ratemaking that provides for recovery of embedded costs as well as approved forecasted costs, and Section 6w(3)(a) directs the utility to include capacity related costs that are included in "base rates, surcharges, and power supply cost recovery factors." He argues that the statute contains nothing indicating that the charge has to be forward looking or market based as CNE suggests, and that it should actually be based on the utility's approved revenue requirement. Mr. Ronk also rebuts Mr. Revere's suggestion that CONE provide a basis for the charge, on the same grounds. He also contends that the Commission has indicated that the SRM charge will be a retail rate that is charged directly to ROA customers.

Mr. Ronk explains that, while Consumers anticipates making PRA purchases in 2018 to serve ROA load if necessary, this does not mean the utility will do so every year. He notes that MISO has projected that Zone 7 may face a capacity shortage in 2022, that the zone may be short of its LCR, and that existing merchant generation has been leaving Zone 7. He contends that Section

6w(6) does not limit the Commission's discretion to determine the term of the SRM charge once it applies to an AES, and that it must apply for a minimum of four years, but a longer term will ensure reliability. This will allow utilities, he argues, to justify the construction of new capacity.

In rebutting Ms. Cantin, Mr. Ronk asserts that the new space created under the choice cap when a customer returns to full service should not be filled, because an AES that has demonstrated that it does not have sufficient capacity will still not have sufficient capacity when the new customer from the queue fills that space. He repeats that the utility cannot plan under such a scenario.

In rebutting Mr. Revere and Mr. Jennings with respect to intersystem sales, Mr. Ronk states that Consumers was a net buyer of energy from the MISO market in over 99% of the hours in 2014, 2015, and 2016, and he assets that within that remaining 1% of hours Consumers is effectively selling energy to itself, clearing it through MISO's settlement system. He states that Mr. Jennings failed to deduct the incremental cost to generate the energy sales and fails to provide sufficient detail about how he used the dispatch model. He also states that Consumers is a net buyer of ancillary services.

Mr. Ronk rebuts the Staff on the proration of charges, saying the charge should be assigned "on a simple in-or-out basis." 5 Tr 276-277. He contends that there is no need to file an updated charge following the AES capacity demonstrations because none of the assumptions will have changed. He further states that AESs are not permitted to pay the utility for capacity under Act 341, and the SRM charge must be a retail charge to retail customers, thus falling within the Commission's jurisdiction. Finally, Mr. Ronk posits that there is nothing in MCL 460.11(1) (regarding rates based on the cost to serve) that suggests that an SRM charge can only be based on incremental capacity.

Initial Briefs

Consumers Energy Company

Consumers begins by arguing that the SRM must have an indefinite term in order to ensure reliability, because construction of new generation is a long-term prospect. Consumers further argues that the charge itself, once levied, must remain with the choice customer for 30-years, for the same reason. Consumers contends that a 30-year charge would be just and reasonable for capacity costs applied to bundled customers, and choice customers should be treated no differently. A new 30-year period would not commence until the initial 30-year period ends, and the AES again fails to make its demonstration. Consumers argues that Section 6w(6) and (7) both support the notion that the Commission can set the term of the charge for any length as long as the initial charge is not less than four years. Otherwise, Consumers states, choice customers will come and go from choice service based on whether a charge is in place or not, thus "gaming" the system. Consumers disagrees with the intervenors who argue that short term market purchases can be used to cover any obligation, because this would not promote long-term reliability.

Consumers claims that its accounting and billing systems are currently unable to allocate the charge on a pro rata basis among an AES's customer base, and thus each AES must make its demonstration on a customer-by-customer basis; and the charge would be levied based on a first-in/last-out customer basis, so that older customers would pay nothing and newer customers would be required to participate. 5 Tr 241. Consumers observes that pro rata billing might become available with the input of time and resources. 6 Tr 384.

Consumers proposes that its ROA tariff be amended to provide that if a customer becomes subject to the charge, then that customer must choose between returning to full service or becoming subject to the charge for 30 years. With this provision, Consumers posits that other customers in the choice queue could backfill an opening under the 10% cap. Consumers says that backfilling may occur only if the customer "returns to fully bundled service before its AES failed to meet resource adequacy requirements." Consumers' initial brief, p. 14 (emphasis in original). Without this amended tariff provision, Consumers proposes that there can be no backfilling of the choice cap with customers from the queue until the expiration of the 30-year term of the charge applied to that customer. This is necessary, Consumers reasons, because of the nature of long-term planning. Again, Consumers envisions a revolving door of ROA customers if this proposal is rejected by the Commission.

Turning to calculation of the charge, Consumers begins with costs embedded in base rates. Consumers states that it started with the approved COSS and created a new classification of the production revenue requirement, breaking these costs down into capacity-related and non-capacity-related. 5 Tr 346. Non-capacity-related costs include fuel expense, purchased and interchanged power expense, other operations and maintenance (O&M) expense, PSCR revenue credits, non-PSCR revenue credits, and transmission expense. Exhibits A-2, A-3. Power supply charges were separated into capacity-related and non-capacity-related as well. Consumers states that its proposed rate design for each rate class ensures that each ROA customer subject to the SRM charge pays the same charge as a comparable full service customer. 5 Tr 372. The rate design in Exhibit A-6, and the tariffs in Exhibit A-8 reflect the separate capacity charges for each rate schedule. 5 Tr 375. The tariffs rely on the 2018 PSCR costs, separated into capacity and non-capacity related for the monthly factors. ROA customers are not subject to non-capacity PSCR costs. Exhibit A-9.

Consumers explains how it concluded that it was not subject to any of the reductions mandated by Section 6w(3)(b), asserting that: (1) it is a net buyer of energy from the market on an annual basis, and thus its net energy market sales under (b)(i) are zero; (2) it does not have off-system energy sales which result in a credit to the charge under (b)(ii) because capacity sales to Alpena are made at a loss; (3) it is a net purchaser of ancillary services, again on an annual basis, and thus has nothing to subtract under (b)(iii); and (4) it has no other energy sales under (b)(iv). 5 Tr 250-251. Consumers disagrees with the Staff and intervenors on the issue of energy market credits, arguing that annual purchases exceed sales, and net annual sales must be considered. Consumers refutes Energy Michigan's calculation of $651 million in 2018 net energy sales revenues, again by noting that it was a net buyer of energy from the MISO market "in over 99% of the hours in 2014, 2015, and 2016 and on an annual basis in each of those years," and positing flaws in Mr. Jennings' analysis. 5 Tr 274; 6 Tr 575-581.

Consumers also disagrees with the Staff's cost proposal, claiming that the Staff was not familiar with what costs are included in MISO's determination of CONE. Consumers contends that the Staff's proposals related to either CONE/CT or capacity costs avoided by contracting to purchase power from qualifying facilities under PURPA must be rejected because Section 6w(3)(a) expressly directs that the charge be based on "capacity-related generation costs included in the utility's base rates, surcharges, and power supply cost recovery factors." MCL 460.6w(3)(a). Consumers notes that neither CONE nor PURPA avoided costs are included in rates, and maintains that the Legislature decided that the charge must be based on the utility's embedded costs plus PSCR costs, allowing for no proxy. In particular, Consumers notes that Mr. Revere asserted that the charge should be based on the cost of a peaking capacity generating unit, but argues that the utility uses its entire generating portfolio to provide capacity. Consumers also points out that the MISO capacity requirement applies throughout the year, stating "Because of this MISO capacity construct, the Company's SRM capacity load needs to be served with its full capacity requirement every hour of the year, which requires the Company's entire capacity portfolio. This operational reality is reflected in the language of Section 6w(3)(a) of Act 341, which requires the charge for the SRM capacity service to be based on the costs of the Company's entire owned and purchased generation portfolio." Consumers' initial brief, p. 30, citation omitted. Consumers also posits that CONE would not be high enough to incentivize building new capacity. 5 Tr 266-267.

Consumers disagrees with any use of a cost allocation method. Consumers contends that the Staff took all production costs from the COSS (except for fuel handling costs) and simply subtracted 25%, providing very little explanation for this method. *See*, 6 Tr 754-755. Consumers alleges that its method complies with the NARUC Manual regarding the classification of capacity related costs, and argues that the Staff's method fails to recognize other capacity related costs, such as intangible plant and other joint and common costs, that should be included. Moreover, Consumers contends, an allocation method is simply inapposite and is not intended for defining what constitutes a capacity production cost. Consumers also notes that the Staff's proposal is not consistent with its proposal in Case No. U-17032, which was adopted by the Commission and which relied on fully embedded costs. Consumers contends that the nature of the service that is provided in both that case and this one is identical. Consumers proposes to use the same method as was adopted for I&M.

Consumers refutes the intervenors' proposed cost calculation methods. Disagreeing with CNE, Consumers again notes that it uses its entire portfolio of resources to supply capacity, and thus the charge should not be tied solely to incremental capacity and peaking plants. Consumers urges the Commission to reject a marginal cost method, because Michigan is an embedded cost method state. Consumers rejects ABATE's proposal because, like the Staff, it relies on excluding

25% of production costs. Consumers rejects Energy Michigan's cost of service argument by noting that it bases its calculation on the approved electric COSS. Consumers asserts that some of ABATE's, CNE's, and Energy Michigan's proposals are outside the scope of this proceeding, and claims that the Commission has already decided that the SRM charge will be billed to retail customers. *See,* January 20 order, p. 6, note 7. Consumers asserts that the charge must apply to retail customers, and AESs may allocate the costs via their contractual relationships with customers in any way they see fit.

Consumers argues that the Staff's proposal regarding summer on-peak charging violates the Section 6w(3) mandate that the charge not differ between bundled and choice load, noting that bundled customers pay for capacity year-round. 5 Tr 383-384. Consumers notes ABATE's argument regarding revenue shifting, and observes that such a proposal may only be considered in a rate case. Consumers also argues that ABATE's proposed demand charge should be rejected because a separate transmission cost must be addressed in a rate case.

Consumers proposes that annual net revenues under Section 6w(3)(b) be reconciled as part of its annual PSCR reconciliation, and that annual determination of the capacity charge occur through a combination of the PSCR process, general rate cases, and a yet-to-be-established stand-alone SRM case process, stating:

> That case should adhere to the following schedule:
>
> • June 1st: Implementation of SRM capacity charge for the Planning Year;
>
> • March 15th: New SRM capacity charge calculation filed by utility, which includes a review and amendment of the capacity charge for changed capacity costs as determined in base rate cases and PSCR filings and decisions. The required true-up of the net energy sales identified in Section 6w(3)(b)(i)-(iv) will occur in annual PSCR proceedings and carry through to the subsequent year's calculation of the SRM capacity charge. The capacity charge recovered through the capacity portion of the PSCR factor would be updated monthly through the PSCR Plan process;

• May 1st: Order for new SRM capacity charge issued by the MPSC; and

• June 1st: Implementation of new SRM capacity charge; process restarts.

> Section 6w(5) requires only this annual capacity charge review case to be completed by December 1st of each year.

Consumers' initial brief, p. 49, note omitted.

<u>The Kroger Co.</u>

Kroger disagrees with the use of the COSS for determining distribution of the SRM charge and with the Staff's proposal that the charge be collected through summer on-peak kWh charges for rate schedules without demand charges and through summer on-peak kW charges for rate schedules with demand charges, calling this a radical change from the status quo. Kroger notes that, currently, capacity costs are recovered year-round through the demand charge. Higher charges occur in the summer due to the summer peak, but the rate design evens out the recovery and has been found to be just and reasonable in numerous proceeding. Kroger argues that the Staff's proposal will result in dramatic increases in summer bills for bundled customers. For Rate GPD, Voltage Level 3, for example, Kroger states that summer power supply rates would move to more than double the average non-summer rate. Kroger urges that the cost be recovered throughout the year, and that demand related costs not be made into energy charges. Otherwise, Kroger contends, customers with high load factors will pay more for power supply than under current bundled rates and intra-class cost shifting will occur. Kroger urges the Commission to reject the Staff's proposals. Finally, Kroger contends that the Staff's proposal should include a gross-up for income taxes.

Wolverine Power Marketing Cooperative, Inc.

Wolverine argues that the capacity charge must be assessed on the AES and not on the customer, because the AES is obligated to serve its customers and to file capacity demonstrations. Wolverine notes that only the AES can decide whether to rely on a utility for capacity or meet the obligation itself, and the customer is not involved. Wolverine contends that "it is fundamentally unfair from a ratemaking standpoint to assess the capacity charge on the customer absent some specific legislative authorization. The AES, as an unregulated business, can decide if and when the cost of capacity is passed on to the customer as a matter of private contract." Wolverine's initial brief, p. 6. Wolverine posits that its viewpoint is supported by the language of Section 6w(6), and further argues that placing the charge directly on the customer will discourage the use of choice.

Wolverine maintains that placement of the charge on the AES does not involve wholesale sales, because it compensates the utility for the cost of obtaining the capacity on behalf of the AES. Wolverine asserts that the ROA tariff with the utility could establish a requirement for a capacity-short AES to pay a retail charge.

Wolverine disagrees with Consumers' 30-year proposal, arguing that the statute requires only four years for the initial term, and annual charges thereafter, where Section 6w(6) states that the charge shall not be assessed for any portion of the load for each planning year for which the AES made its demonstration. Wolverine urges the Commission not to impose a locational requirement in this proceeding.

Energy Michigan, Inc.

Energy Michigan states that the capacity charge must not conflict with the MISO tariffs, and must apply only to the portion of the load for a planning year that was not satisfied in the demonstration. Energy Michigan argues that Section 6w(3) requires that the calculation of the charge be based on inputs to base rates, and must comply with cost of service principles as required under MCL 460.11, thus the charge cannot be substantially more or less than the actual cost to the utility of obtaining capacity for ROA customers.

Energy Michigan posits that capacity is an electric attribute of physical generation facilities, and thus cannot be determined by simply adding up the fixed cost of such facilities. Energy Michigan argues that the costs of the electric attribute can be determined by looking at CONE, or the MISO PRA price, or the capacity portion of the embedded costs of a generation facility; and that the charge must be based on the costs of the newly acquired incremental capacity because historical investments are not relevant.

Energy Michigan proposes an alternative calculation method for the charge. Noting that Michigan has no load growth, Energy Michigan proposes a cost sharing mechanism for new resources on grounds that maintaining the LCR is a forward looking process. All new resources qualified as ZRCs for Zone 7 would be eligible for cost sharing, except for the purchase or output of an existing resource already running in Zone 7 and a new resource built outside the zone. The cost of capacity only would be shared, at the value of CONE, so the utility should receive CONE minus the ACP, shared on a pro rata basis by all LSEs in the utility’s service area. 6 Tr 645-650. The SRM charge would commence if an LSE fails to participate in the cost sharing. The charge itself would be based on zonal CONE, which, Energy Michigan contends, would comply with MCL 460.11. Or the charge could be based on embedded costs, but with the full amount of energy market sales deducted. According to Energy Michigan, this puts the net capacity cost at $914 million or $300.59 per MW-day. Exhibit EM-7; 6 Tr 709-710.

Energy Michigan further argues that the charge must be paid by the AES to the utility, under the language of Section 6w(6). Any other structure, according to Energy Michigan, would conflict with MISO's tariff and create a competitive disadvantage for AESs, and place a burden on customers that is not appropriate. This would allow the AES to spread the cost across its load base and avoid placing a discriminatory charge on particular customers. In order to avoid double-billing, Energy Michigan posits, the charge should be applicable only for the delivery year in which the AES fails to meet its obligation, and not the entire four years addressed in the statute.

Constellation NewEnergy, Inc.

CNE urges the Commission to adopt an SRM charge for Consumers of between $130/MW-day and $255/MW-day, claiming that Consumers' proposal comes in at $511/MW-day; and argues that in no event should the charge exceed CONE for Zone 7, which was set at $260/MW-day for the 2017/2018 planning year. CNE also contends that the utility should be required to produce a planning model in future charge cases that will isolate Consumers' capacity costs from its energy costs. In the meantime, CNE supports use of the average and excess energy weighting method applied by Dr. Makholm to derive a charge of $255/MW-day. CNE contends that this is reasonable in light of how close it is to MISO CONE. CNE argues that Consumers' proposal for how to set the charge does not comply with the statute and simply restates embedded costs with no attempt to distinguish energy from capacity. CNE maintains that a planning model would solve these problems by isolating capacity-only AES demands.

As alternatives for determining the charge, CNE offers the price of ZRCs from Consumers' own auction in Case No. U-18382 of $164/MW-day or less; or the 50% of MISO CONE applied by Consumers for analysis purposes in Case No. U-18250, which was $130/MW-day in 2016; or

MISO CONE for Zone 7 of $260/MW-day, noting however that CONE includes the cost of energy for new generation, as well as capacity.

CNE further argues that the charge should be assessed on the AES and not its customers under the clear language of Section 6w(6) which states that "Any electric provider . . . shall give notice . . . if it . . . expects to pay a capacity charge." CNE contends that the law thus clearly imposes the payment obligation on the AES. CNE objects to Consumers' proposal to bill ROA customers as simply based on a "perceived jurisdictional defect in the statute." CNE's initial brief, p. 13. CNE reasons that AESs should be permitted to manage the charge among their customers and on the basis of their entire portfolio, and that ROA customers should not be forced into the center of disputes between the AES and the utility. CNE suggests that the terms of the ROA tariff be amended to allow the AES to pay the charge for the relevant portion of its load, and, to avoid double-payment, suggests that the charge be reduced by the PRA clearing price.

CNE objects to Consumers' 30-year term proposal as unreasonable and a violation of Section 6w(3). CNE notes that Consumers has stated that it intends to acquire capacity through capacity markets, undercutting the utility's argument that capacity will be supplied through newly built generation. CNE points out that bundled customers are not paying a 30-year capacity surcharge, and notes the language of Section 6w(6) which states that a charge "shall not be assessed for any portion" of load for each planning year in which the AES makes its demonstration. CNE recommends a one year term. CNE further argues that "the calculation of the SRM charge should be based on forecasted data during the term of the charge, including projected energy and ancillary services market clearing prices which are forward looking values that should be deducted from the SRM price." *Id.*, p. 17. CNE notes that Consumers' proposed charge is simply based on annual data.

The Attorney General

The Attorney General does not take a position on any issue other than the proposed 30-year term of the charge. The Attorney General disagrees with this proposal by Consumers on grounds that it is unreasonable, and notes that if the utility's investments are prudent and used and useful, the costs will be recovered. The Attorney General also notes the language of Section 6w(6) stating that the charge shall not be assessed for any portion of capacity obligations for each planning year for which the AES made its demonstration, and argues that 30 years is arbitrary. The Attorney General states "the Commission needs to maintain flexibility in its rules and procedures because MISO is not foreclosed from pursuing approval of a forward capacity auction in the future. In addition, market conditions, state capacity needs and capacity costs will likely change within the next 30-years." Attorney General's initial brief, p. 18.

ABATE

ABATE contends that Consumers' proposed SRM charge is over $600/MW-day and is unreasonable. ABATE asserts that Consumers did not properly deduct the amounts required under Section 6w(3)(b), and that the calculation of the charge must exclude generation costs that are not associated with the provision of ZRCs, because only ZRCs will be provided to customers who become subject to the charge and ZRCs provide no energy. ABATE reasons that Consumers should not have treated the 25% energy allocation of fixed production costs as capacity related, because this will result in AES customers paying for energy related services that they do not receive from the utility. ABATE contends that the 25% should be classified as non-capacity related production cost, and that this would allow the same charge to apply to both bundled and choice customers.

ABATE maintains that Consumers' proposal would allow the utility to collect revenue well in excess of its incremental cost to provide capacity, which could end up to be as low as the 2017/2018 MISO ACP of $1.50/MW-day. ABATE states that Consumers' proposal results in a charge to a Rate GPD customer of $633.64/MW-day, which ABATE calls a 115.7% overrecovery.

ABATE urges the Commission to require Consumers to make a filing after the 2018 capacity demonstrations and the rate case are completed, to update the charge "to reflect the actual AES customer Capacity Charge billing units and Consumers' actual incremental cost to provide capacity to these customers." ABATE's initial brief, p. 9.

ABATE also contends that Consumers improperly uses an energy charge to recover transmission costs which are incurred, primarily, under the MISO tariff based on a monthly demand charge. ABATE contends they should be recovered via a demand rate because transmission costs are not energy related, and this will align with cost causation and reduce cross-subsidization between classes. *See,* Exhibit AB-3.

ABATE also disagrees with Consumers' proposed calculation of the capacity related PSCR factor because it allocates capacity costs to retail rate classes using an energy allocation, and it does not account for energy losses between voltage classes. ABATE maintains that the PSCR capacity related factor should be allocated based on 100% demand 4 CP, and should account for those loss differences. Exhibit AB-4. ABATE posits that Consumers' proposal would over-allocate costs to high load factor customers and fails to align cost recovery with causation.

ABATE avers that a perpetual SRM conflicts with the statute, and would require further legislation. ABATE also objects to the proposed 30-year term as anticompetitive, in conflict with the statute, and as a method for trapping customers. ABATE notes that the language of Section 6w(6) speaks to a single planning year at a time. ABATE objects to the proposal to require the lowering of the choice cap, on grounds that it could put an end to choice in Consumers' territory and is not authorized by the statute. ABATE also characterizes the first-in/last-out proposal as unnecessary and unreasonable, stating that it would interfere with contractual arrangements between AESs and their customers. ABATE argues that the administrative convenience of the utility should not be given priority over the ability of AESs and customers to freely contract.

ABATE disagrees with the Staff's assertion that any costs in excess of MISO CONE (or the value arrived at in Case No. U-18090) are energy related, arguing that legacy costs are not necessarily energy related. ABATE also disagrees with the Staff's proposed rate design, contending that it results in significant shifts between classes. ABATE claims that for Rate GPD customers, Voltage Level 1 would be reallocated over $16 million from Voltage Levels 2 and 3, and argues that such reallocations among rate classes are not sanctioned by Section 6w. ABATE argues that the SRM charge should not result in alteration of the spread of the total revenue requirement among classes. Finally, ABATE rejects the Staff's proposal for a summer on-peak charge, on grounds that it violates cost of service principles.

<u>The Commission Staff</u>

The Staff states that the SRM should remain in place indefinitely, observing that statutes that do not have an expiration date continue in perpetuity. Noting the language of Section 6w(6), the Staff asserts that the charge should be in place for one year, and only for the portion of the load that does not pass the demonstration. The Staff points out that under Consumers' proposal, the charge could be in effect for a year in which the AES made its demonstration, which would violate Section 6w(6). The Staff maintains that the language of Section 6w(8)(b)(i) requires that if, in its initial demonstration, an AES is unable to satisfy its obligations for any of the first four planning years, then its load will be subject to the SRM charge for each of those first four planning years.

The Staff contends that a 30-year term is discriminatory and contradicts the plain language of the statute. The Staff maintains that the sole exception to the one year term of the charge is laid out in Section 6w(8)(b)(i) for the first four planning years.

Turning to the calculation of the SRM charge, the Staff recommends that the Commission include only costs utilities directly incur to supply capacity. The Staff's first proposal is to identify appropriate production costs, and consider only costs corresponding to the cost of a CT as capacity related, because CTs are the least costly method for producing capacity and any other method inevitably involves considerations that go beyond capacity. 2 Tr 37. The Staff recommends use of the levelized per-year cost of a CT as determined in Consumers' recent PURPA case, Case No. U-18090, with the production allocator

> modified so that the percentage applied to determine which portion of the costs allocated using the production allocator (and other related costs and offsets) are capacity related results in said cost on a MW/year basis. (6 TR 755.) Or in other words, the demand portion of the production allocator, which is currently set at 75%, would be adjusted (up or down) so that when applied to the Company's approved applicable costs, the result limits the capacity revenue requirement to the cost of a CT unit on a MW/Year basis.

Staff's initial brief, p. 13.

The Staff also proposes an alternative method based on using the approved COSS from Case No. U-17990 to identify costs incurred to supply capacity. This also begins with identification of appropriate production costs, and then applies the current demand weighting of the production allocator of 75% to those costs. 6 Tr 754-755. The Staff contends that Consumers' proposed method conflicts with Section 6w(8)(a), which requires that the charge include capacity related generation costs included in the utility's base rates, surcharges, and PSCR factors. The Staff states that Consumers included non-capacity related costs, and that the utility conflates "capacity related" with "demand related." The Staff notes that Mr. Ronk correctly testified that there are costs that are neither energy nor capacity related. 5 Tr 344. Thus, the Staff argues, the NARUC Manual does not specifically address the classification of these costs because they cannot be classified into either energy or capacity. The Staff urges the Commission to adopt the cost causation approach that it traditionally uses.

The Staff also disagrees with Consumers' arguments regarding the I&M case, stating that "Staff considers its responsibility in this case to be an independent review of capacity costs pursuant to the statutory requirements set by the Legislature in Act 341. The Legislature passed Act 341 in 2016, long after the Commission decided U-17032." Staff's initial brief, p. 18. The Staff avers that the cases are not comparable. The Staff also argues that Consumers' proposal does not follow the I&M findings in any case, because Consumers did not use the same definition of non-energy costs as was applied in that case.

The Staff contends that Consumers has not applied the dictates of Section 6w(3)(b) correctly, observing that the revenues from the sales listed in that subsection are all recorded in the intersystem sales account. The Staff notes that the statute speaks of "all energy market sales" as an offset against the capacity cost, and provides no exemptions.

The Staff agrees with Consumers that the statute contemplates a single capacity charge between similarly situated choice and bundled customers, and recommends that the results of the allocation of capacity related costs in the COSS be used to set a separate charge for each customer class.

The Staff recommends that the calculation of the capacity charge be based on on-peak summer kWh charges for rate schedules without demand charges, and on-peak summer kW charges for rate schedules with demand charges. The Staff finds that this is the best proxy for contribution to capacity related cost incurrence. Acknowledging that this measure is not ideal for classes with large numbers of smaller customers, the Staff

> recommends dealing with this issue by selecting some series of hours likely to become the CP and billing on those hours, as this spreads the cost responsibility over all hours that could potentially become the CP. Staff recommends on-peak summer kWh, as it only incorporates the months in which the 4 CPs used for allocation occur, while balancing the competing priorities of sending an effective price signal and not shifting the peak such that the rate no longer reflects the hours likely to become a CP. (6 TR 759.)

Id., p. 23. If the Commission chooses one charge for all customers, the Staff recommends on-peak kWh. 6 Tr 760. The Staff asserts that its proposal best reflects cost allocation and cost causation.

The Staff supports allocation among AES customers on a pro rata basis, because capacity planning is performed on an aggregate basis, and specific resources are never assigned to specific customers. Additionally, the Staff observes that Consumers would charge the choice customer the full charge for the full amount of load even where the AES had made its demonstration for a portion of the load, thus conflicting with the language of Section 6w(6). The Staff notes that Mr. Ronk testified that the utility would attempt to comply with pro rata billing. *See,* 5 Tr 328.

The Staff objects to Consumers' proposal regarding the ROA tariff and the 10% cap, pointing out that lowering the cap conflicts with MCL 460.10a(1)(i) and with the choice allotment procedures adopted by the Commission in the April 28, 2017 order in Case No. U-15801, Appendix A. The Staff is skeptical regarding the notion that ROA load switching on an annual basis would impair the utility's ability to plan, noting that there are a considerable number of customers waiting in the choice queue (and seven AESs serving Consumers' territory).

Finally, the Staff recommends that the reconciliation required by Section 6w(4), which is limited to revenues and costs required under Section 6w(3)(b), be approved. The Staff also recommends that the PSCR factor not be split into capacity and non-capacity portions, on grounds that it is unnecessary; and argues that it is impossible, in any case, to identify which costs are in the factor and which are in rate base, thus leading to mistakes. The Staff notes that its proposal effectively assumes that all capacity costs are in the base.

Reply Briefs

Wolverine

Wolverine reiterates its arguments in opposition to the proposed 30-year term and imposition of the SRM charge on the ROA customer, referring to the plain language of the statute in Section 6w(3), (6), (7), and (8), and the clear responsibility of the AES for capacity service and customer service. Wolverine points out that Section 6w(3), (7), and (8) all refer to AES load.

Energy Michigan

Energy Michigan reiterates its arguments in opposition to a perpetual SRM, contending that it is unlawful for this Commission to bind future Commissions to a particular policy that would require legislative action to undo. Energy Michigan describes the SRM as a tool for the Commission to use to address reliability, but argues that the Commission can only determine on an annual basis whether to "implement an SRM for the applicable year." Energy Michigan's reply brief, p. 4.

Energy Michigan also repeats its arguments regarding the 30-year term, stating that Consumers failed to identify how the alleged gaming would harm the utility or ratepayers. Energy Michigan advocates imposition of the charge on the AES on grounds that it is required by the statute which throughout refers to "AES," "AES load," or "load." Energy Michigan points out that under Section 6w(7) only an AES can reassign its capacity to another provider – an ROA customer cannot.

Energy Michigan contends that non-ZRC costs should be excluded from the PSCR factor, because only a ZRC is a valid capacity related expense for the PSCR, and other purchased power expenses should be allocated to full service customers only.

Energy Michigan repeats its arguments opposing the Staff's rate design. Energy Michigan notes that the PRMR is an annual obligation determined by MISO based on the previous year's actual peak, and a ZRC is an annual product. MISO bills the capacity charge equally over the planning year per MW of PRMR. Energy Michigan thus contends that the SRM charge should be viewed similarly as simply the collection of an annual expense over the course of a year. Energy Michigan argues that there is no need to implement a significant rate design change outside of a rate case.

Constellation NewEnergy

CNE contends that the capacity charge should be no higher than MISO CONE and repeats its support for a planning model that would incorporate forward looking costs. CNE notes that Section 6w(3)(a) and (b) speak of the "applicable term of the capacity charge," and argues that this indicates that the charge calculation must be based on forecasted data for the term of the charge, whereas Consumers' proposal is based on annual data used in Case No. U-17735.

CNE reiterates that the charge should be placed on the AES and not on the customer, arguing that Section 6w(6) requires this; that the AES is responsible for procuring capacity and making the demonstration; and that charging the customer may violate existing customer contracts and prohibit AESs from making competitive product offerings. CNE also urges the Commission to reject pro rata billing in any case, and let AESs determine which customers will pay. CNE repeats its opposition to the 30-year term and the lowering of the 10% choice cap.

CNE urges the Commission to defer any ruling on a true-up mechanism, and allow this issue to be addressed on a case-by-case basis based on actual facts and circumstances, because any Commission ruling here would be premature and advisory. CNE also favors rejecting the notion of an annual redetermination of the capacity charge. CNE argues that Consumers' proposed timeline will not work because there is simply not enough time between March 15 and May 1 to make such a determination, stating:

> CNE recommends that the Commission open a standalone docket each year for purposes of setting the SRM capacity charge. The setting of the SRM capacity charge should not be completed as part of a power supply cost recovery case or a general rate case, which are already complex proceedings that should not be made more complex by interjecting SRM related issues in them. Parties who are solely interested in addressing SRM-related issues should not be required to participate in these other proceedings to be heard on SRM issues. By law, the proceeding should be commenced in time for the contested case process to conclude by December 1 of each year. Notice of the SRM charge should be provided each year by December 1 before the new SRM charge is implemented the following June 1st.

CNE's reply brief, p. 12.

<u>ABATE</u>

ABATE repeats its objection to Consumers' classification of the 25% energy allocation as capacity related, and notes that the Staff, CNE, and Energy Michigan agreed that this was inappropriate. ABATE argues that Consumers must account for its actual incremental costs to provide capacity to ROA customers, and repeats its request for an update to the charge. ABATE states that it agrees with Consumers' suggestion that the issue of whether an energy or demand charge should be used to recover the SRM costs be addressed in a rate case. ABATE reiterates its opposition to the 30-year term, the perpetual SRM, and the first-in/last-out billing proposal. ABATE also opposes the Staff's rate design and summer on-peak collection proposals, and argues that they should both be addressed in a rate case.

Michigan Chemistry Council

MCC opposes the notion of an indefinite term for the SRM, arguing it is inconsistent with Section 6w(8)(b) and (6). MCC contends that the statute does not provide for an indefinite term, and that the Commission only has the power granted explicitly by the statute. MCC opposes Consumers' 30-year term as excessive, anticompetitive, and unsupported by the language of the statute. MCC also disagrees with the Staff's contention that the initial SRM charge is for four years, arguing that there is a potential for double-recovery and that the charge can only apply during the delivery year for which the AES failed to make its demonstration. MCC favors placing the charge on the AES, and not on customers, based on the language of Section 6w(6) and the fact that AESs are responsible for managing their own customers and for procuring capacity. MCC maintains that the AES should be able to spread the cost across its load base in any way that it sees fit. MCC also opposes the proposal to reduce the choice cap, describing it as an attempt to circumvent the choice law.

MCC agrees with the capacity charge proposal made by Energy Michigan which relies on a sharing of the costs of new capacity, arguing that the cost sharing should be limited to the capacity costs of the new resource and not total costs. MCC contends that the SRM charge cannot be based on historical costs of investments that are not providing capacity service, and favors Energy Michigan's proposal to base the cost on CONE.

The Staff

Responding to Consumers, the Staff disagrees with the utility's interpretation of how to calculate net revenues under Section 6w(3)(b), arguing that the statute requires subtraction of all non-capacity related generation costs net of projected fuel costs, and that "'The costs associated with purchasing energy from the market when the Company's plants produce less than its customers use are included in rates as an energy cost, appropriately.' (6 TR 755–756.)" Staff's reply brief, p. 2. The Staff argues that the Commission may not read into the statute language that is not there.

Turning to its recommended calculation method, the Staff states that it uses the cost of a CT to identify what portion of the cost of Consumers' generating plants is incurred to provide capacity only, under Section 6w(3). The Staff states that it proposes using Consumers' company-specific CT cost as presented in the PURPA case, Case No. U-18090. The Staff contends that its method identifies costs incurred to provide capacity only, whereas Consumers' method mistakenly includes costs incurred to provide more than capacity. The Staff objects to the paucity of information provided with Exhibit A-1, which identifies capacity related costs as a single line item without further explanation, and argues that this line item is, in actuality, simply total production costs minus energy costs.

With regard to its proposed use of the production allocator, the Staff offers a new position:

> Should the commission agree with Staff's proposed identification of capacity costs as those which could add up to no more than the cost of a CT, and also agrees with other parties that the difference between this new percentage and 75% should not be considered energy related, Staff proposes a compromise position. A compromise position would be to maintain the overall 75% of the production allocator, but split the demand piece into two portions — a capacity-demand portion that is set at the percentage necessary to set the capacity revenue requirement equal to the cost of serving the Company's capacity using a CT, and a non-capacity-demand portion that is set to make up the difference between the capacity-demand portion and 75%.

Staff's reply brief, p. 7.

Responding to ABATE's proposal for updated billing determinants, the Staff indicates that it agrees with Consumers that such an update should occur in a rate case or another contested case proceeding. The Staff disagrees with ABATE's suggestion that the charge be prorated on the basis of peak load contribution, because this would not match the determinations made in the COSS and adopted in the last rate case with regard to class cost responsibility. The Staff further disagrees with Kroger's suggestion of an income tax gross-up, finding it confusing and noting that the Staff directly calculated the revenue requirement for capacity.

The Staff objects to CNE's recommendation of a planning model, arguing that the Staff's method is simpler and easier to implement, and is an extension of the Commission's current allocation and classification methods. The Staff also disagrees with CNE's premise that CONE should provide an upper limit on the charge, calling it arbitrary and inconsistent with Section 6w(3). The Staff explains that its own PURPA/CT cost suggestion is simply a way of identifying appropriate costs and not a cap.

The Staff also takes issue with the intervenors who call for the charge to be placed on the AES, contending that Section 6w, when read as a whole, requires that the charge be placed on the ROA customer, to make it practical and enforceable. The Staff notes that the service itself is provided directly to the customer and not to the AES. The Staff also points out that the statute requires that the charge paid by bundled load and AES load must not differ, and that it would be impossible for the Commission to carry this out if the charge is placed on the AES. The Staff notes that if the Legislature ordered the Commission to set a wholesale rate, then Section 6w is preempted by federal law.

While Section 6w(6) appears to address "electric providers," the Staff goes on to argue that it cannot be read in isolation and that if the Legislature wanted the AES to be charged it could have said so. The Staff observes that Section 6w(7), like other subsections, is addressed to "the portion of that load," and that only the AES can decide whether to provide forward capacity service or not. Thus, it would be impractical to expect customers, under Section 6w(6), to provide the Commission with notice as to whether they expect to pay a charge. The Staff maintains that the real effect of Section 6w is to mandate that incumbent utilities must provide a forward-planning state reliability service, which the AES may or may not choose to provide. MCL 460.6w(7). The Staff posits that the benefit of increased reliability flows to the customer and not the AES, and it only makes sense to charge the customer. The Staff proposes that this interpretation harmonizes with MCL 460.11 and carries out the full intent of Section 6w without rendering it nugatory or frustrating its purpose. The Staff avers that the Legislature is presumed to know the law in effect at the time of its enactments.

In response to Energy Michigan, the Staff disagrees with a charge set on the basis of newly acquired, incremental capacity, because it would violate the cost of service requirement and result in discriminatory rates. The Staff also disagrees with Energy Michigan's proposal to remove all revenues from sales into the MISO market, on grounds that Energy Michigan has misidentified what is a "sale." The Staff contends that only the amount bought that is above the utility's production should be considered a "purchase," and only the amount sold above production should be considered a "sale."

Consumers Energy Company

Consumers begins by positing that the common theme of the Staff and intervenors' proposals is to reduce the SRM charge by offering a cap at CONE. Consumers explains that CONE is actually a MISO determination based on the concept of a new CT plant that is assumed to be used infrequently, whereas the utility actually uses its entire portfolio to provide capacity to any customer. Consumers highlights that the condition precedent to imposition of the charge is the AES's failure to make its demonstration, and that, when imposed, ROA customers and full service customers must pay the same charge pursuant to Section 6w(3)(a) which must be based on rates, surcharges, and PSCR factors.

Consumers repeats its arguments in favor of a perpetual SRM and a 30-year term for the SRM charge, noting that Section 6w(8)(b)(i) requires that the charge be assessed to an AES's uncovered retail electric load for each of the four planning years from June 1, 2018, through May 31, 2022. Consumers contends that a one-year charge would act as a disincentive to both the utility and the AES to procure capacity for the long term. Consumers alleges that Section 6w(3), (6), and (7) support its viewpoint. Consumers states that "a reasonable compromise position would be at least a 10-year term." Consumers' reply brief, p. 11.

Consumers objects to the Staff's proposals based on either CONE or PURPA avoided costs, or on a 75% allocation of demand related costs, noting that Section 6w(3) requires the use of base rates, surcharges, and PSCR factors. Consumers observes that the Legislature did not evince an intent to use a proxy cost or an incremental cost but specifically called for "generation costs included in the utility's base rates." Turning to the Staff's proposal in its initial brief to adjust the 75% limit up or down to reflect the cost of a CT unit on a MW/year basis, Consumers responds that the Staff relies heavily on factual material from the NARUC Manual that was not placed in the record. Consumers argues that the Staff is essentially saying that ROA customers should not have to pay for any capacity investments in the utility's existing baseload and intermediate generation plants because those customers do not receive energy from those investments, and posits that this position ignores the fact that capacity service is provided to all customers from the entire generation portfolio, including base load coal and gas plants, PPAs, intermediate plants, and peaking units; and units which provide energy also provide capacity. Consumers contends that ROA customers should not be allowed to cherry-pick resources. Consumers asserts that utility investments in capacity, including those that also have the effect of lowering energy costs, benefit all customers because they reduce the MISO locational marginal price to which all customers are equally exposed, including ROA customers.

Consumers reiterates its arguments in support of the calculation method adopted for I&M, stating that the Staff's response is conclusory and the service at issue is identical. Consumers further argues that the Commission's findings in the September 22, 2017 order in Case No. U-18250, pp. 63-64, show that the Commission is aware that all of Consumers' capacity resources will come into play in complying with Section 6w. The utility asserts that the fact that bundled customers obtain energy from a PPA does not mean that the capacity provided under that PPA is not used to serve all customers.[7] Consumers contends that the Staff's proposal would discriminate against full service customers by forcing only those customers to pay for the existing fleet of capacity resources, when Section 6w(3) requires that the charge not differ between full service and ROA load.

Consumers also objects to the Staff's use of a category of costs that are non-energy costs, claiming that there was little information on the record to describe this category. *See*, 6 Tr 779. Consumers believes that ROA customers cannot be excluded from the capacity portion of the PSCR factor, as this would also violate Section 6w(3).

In response to ABATE, Consumers argues that the 25% energy costs should not be excluded, and that the allocation of costs, and the nature of the costs, are two different issues. Consumers asserts that the charge must include all of the costs associated with its generation portfolio that are used to provide ZRCs. Consumers objects to CNE's and Energy Michigan's proposed restriction

[7] Consumers notes that both its PPA with the Palisades Nuclear Plant (Palisades) owner and another PPA with Midland Cogeneration Venture, LLP, contain specified capacity costs that far exceed CONE. Consumers' reply brief, p. 24, n. 4.

to the value of CONE, and argues that Energy Michigan's alternative proposal is outside the scope of this proceeding and the LCR should not be considered in any case.

Consumers repeats its assertion that it has no energy or ancillary sales revenues to credit against costs. Consumers agrees with the Staff's acknowledgement that many issues related to a summer on-peak charge would affect full service customers, and argues for a decision in a rate case. Consumers does not object to ABATE's proposal for use of a demand rate but states that the rate design should be done in a rate case. In answer to ABATE's criticisms of the PSCR factor proposal, Consumers notes that the PSCR factor is currently calculated as a uniform factor for all customer classes. In response to Energy Michigan's arguments regarding the MISO tariff and the transfer of a PRMR to another LSE, Consumers explains that MISO's peak load contribution process is regularly used to shift capacity obligations among LSEs, and can be used to prevent an ROA customer from being double-billed.

Consumers asserts that the SRM charge is a retail charge designed to recover the cost of capacity used to serve retail load, and points to its tariff, Rule C5.2(D), which makes the customer responsible for the payment of bills for charges incurred. Consumers reasons that Section 6w is an action by the Legislature to make the incumbent utility the capacity supplier of last resort, and reminds the Commission that there is a cost associated with this service. Consumers states, "AESs remain free to contract with their ROA customers for reimbursement of SRM capacity charges incurred by the customers if they want them to remain indifferent to the AES's failure to provide sufficient capacity for said customers." Consumers' reply brief, p. 34.

Regarding the ROA queue, Consumers asserts that an ROA customer that has become subject to the SRM charge must either return to full service or be subject to the charge for the applicable term, but that in order to not be subject to the charge, the customer must return to full service before the relevant AES has failed to make its demonstration. *Id.,* p. 35. (It is unclear how the customer would have discovered that it is subject to the charge.) Consumers contends that evaluating whether to retain the extra capacity as was suggested by Ms. Cantin is not workable or fair.

Discussion

The Terms of the SRM and the Capacity Charge

The parties disputed whether the SRM continues in perpetuity or not, with some parties arguing that the Commission could establish the SRM for the first four years as required by Section 6w and then discontinue the mechanism thereafter. The Legislature, in its wisdom, crafted Section 6w to give the Commission a tool for better ensuring the reliability of electric supply for Michigan's electric service ratepayers over the long term. Section 6w(1) and (2) indicates the flow of options for providing this tool, beginning with the potential approval by FERC of an ISO's resource adequacy tariff that provides for a capacity forward auction, moving to approval of a PSCM, and then, in default of either of those options occurring, examination of an SRM. The latter describes the situation in Michigan. *See,* n. 1, *supra.*

Section 6w(2) provides that "If, by September 30, 2017, [FERC] does not put into effect a resource adequacy tariff that includes a capacity forward auction or a prevailing state compensation mechanism, then the commission shall establish a state reliability mechanism under subsection (8). . . . If the commission implements a state reliability mechanism, it shall be for a minimum of 4 consecutive planning years beginning in the upcoming planning year;" and Section 6w (3) provides that "After [April 20, 2017], the commission shall establish a capacity charge as provided in this section." The first quoted sentence indicates that the Commission "shall" establish an SRM, and the last quoted sentence indicates that the Commission "shall" establish a capacity charge. The fact that the intervening quoted sentence begins with "if" does not persuade the Commission that the SRM is meant to be optional – it is, after all, a mechanism. The mechanism may not result in the shifting of a capacity obligation from an AES to an incumbent utility every year, but that does not mean the mechanism itself should cease to exist, or there is no need for the mechanism to continue in perpetuity in order to ensure adequate electric supplies over the long term. The mechanism will continue to be a tool at the Commission's disposal until amendment or repeal of Section 6w. The Staff correctly observes that any statute that does not have an automatic expiration date or sunset provision continues in perpetuity until it is amended or repealed by the Legislature alone. No administrative agency may amend or repeal a statute.

The Commission finds that Section 6w does not limit the term that a charge may remain in place, with the exception of the language just quoted providing that "If the commission implements a state reliability mechanism, it shall be for a minimum of 4 consecutive planning years beginning in the upcoming planning year." MCL 460.6w(2). When this language is read in conjunction with the requirement under Section 6w(8)(b)(i) that "If a capacity charge is required to be paid under this subdivision in the planning year beginning June 1, 2018 or any of the 3 subsequent planning years, the capacity charge is applicable for each of those planning years," the Commission concludes that the Legislature intended for the first four consecutive planning years to be treated as a group, and that any charge applicable to any of those first four planning years is also applicable to every other year in the first four planning years.

Other than this limitation applicable to the first four planning years, Section 6w provides no indication as to the required term of the charge. The Staff and others argue that a term longer than a year would violate the language of Section 6w(6) which states that a "capacity charge shall not be assessed for any portion of capacity obligations for each planning year for which an [AES] can demonstrate that it can meet its capacity obligations." The Commission disagrees. This sentence makes clear that a charge shall not be assessed <u>for</u> a planning year for which an AES can make its demonstration, but it does not say that a charge may not be assessed <u>in</u> a planning year for which an AES can make its demonstration. The Commission concludes therefore that Section 6w allows for a charge to be assessed in a planning year different from the planning year for which the AES failed to show sufficient capacity and for which the utility may recover capacity costs from ROA customers.

That said, the statute thereafter focuses on one year at a time, where it requires that "each year" electric utilities, AESs, cooperatives, and municipally-owned utilities shall make their demonstrations "for the planning year beginning 4 years after the beginning of the current planning year." MCL 460.6w(8)(a) and (b). As some intervenors note, the MISO process is also an annual one. In this context, and bearing in mind that this is the first group of cases setting a capacity charge, the Commission finds that the charge (with the exception of the first four consecutive planning years) should be imposed on an annual basis for a single year. This ensures that the charge comports with the requirements of the statute while avoiding imposition of the charge on the initial group of ROA customers for a term that is unduly burdensome.

The Commission is not persuaded that Consumers' long-term planning requires a 30-year charge. The utility indicates in its testimony that any ROA capacity burden might be met through participation in the PRA, EO resources, DR resources, and PPAs, as well as newly-built generation; and Consumers acknowledges that in the short run it is most likely to rely on the MISO PRA. 5 Tr 241-242. This evidence, along with Consumers' proposal of a 10-year term in its reply brief, belies the need for 30 years of payments. Moreover, the Commission is not convinced that an annual charge will act as a disincentive to long-term planning, because (with the notable exception of this first case) the capacity obligation that is under examination is always four years forward. Four years is sufficient time to lock-in numerous types of resources, including DR resources, EO resources, PPAs, resources purchased in the MISO PRA, and even new gas plants. Any additional capacity burden that is shifted to an incumbent utility will be incremental for that utility, and there are four years of advance notice. The Commission finds that the initial charge that is levied on choice customers at the conclusion of a show cause proceeding for planning years 2018-2021 shall be the first four consecutive planning years, and any charge levied thereafter at the conclusion of a show cause proceeding shall be levied and applicable for a single year.

The Commission is sympathetic to the utility's concern with AES customers potentially going on and off utility capacity service due to market conditions in any given year and how this may cause the utility's full service customers to bear costs associated with arranging for new capacity for AES customers that then return to an AES for capacity service when market conditions improve. But given the four-year notice and the ability for the utility to secure shorter-term capacity supplies, this potential concern with capacity pricing arbitrage does not warrant the Commission setting an excessive 30-year term at this time. The Commission will, however, monitor this situation and consider a term longer than one year if needed to ensure all customers are treated equitably and cost shifting is avoided.

The Method for Determining the Capacity Charge

The record in this matter includes a wide range of competing proposals, with differences among the proposals broad enough to make each comparison apples to oranges. Moreover, some areas of analysis are highly conceptual but lack sufficient details and mechanics to actually allow for implementation. Fortunately, the statute provides significant guidance in Section 6w(3)(a), where it instructs the Commission to begin the calculation of the charge by including "the capacity-related generation costs included in the utility's base rates, surcharges, and [PSCR] factors," regardless of whether those costs result from owned, purchased, or leased resources. The Commission finds that, based on the record in this case, it is reasonable to begin with embedded costs contained in the full portfolio of resources, and this comports with the method adopted by the Commission in the I&M case. The Commission finds Consumers' proposed method, which begins with total embedded production related costs and subtracts the non-capacity-related costs of fuel expense, purchased and interchanged power expense, other O&M expense, PSCR and non-PSCR revenue credits, and transmission expense, to be a reasonable method under Section 6w(3)(a). 5 Tr 347; Exhibit A-3.

However, unlike the I&M case[8] (which was not decided under Act 341), Section 6w(3)(b) goes on to list amounts that must be deducted from embedded costs, including (net of projected fuel costs) all energy market sales, off-system energy sales, ancillary services sales, and unit-specific bilateral contract sales.[9] Consumers posits that on an annual net net (net of projected fuel costs, and net of total purchases or total losses) basis, it has nothing to deduct. However, the statute says nothing about making this determination on an annual net net basis. The statute says "subtract all non-capacity-related electric generation costs . . . net of projected fuel costs, from all of the following: (i) All energy market sales. (ii) Off-system energy sales. (iii) Ancillary services

[8] As ABATE, Energy Michigan, and the Staff point out, Case No. U-17032 is distinguishable from this case in many ways. It was required by a tariff approved by PJM, a different regional transmission operator. In that case, FERC had previously approved PJM's forward capacity auction tariff; whereas, in this case, FERC rejected MISO's forward capacity tariff proposals (the CRS and the PSCM) which, if approved, would have prevented the necessity of setting an SRM charge. *See*, n. 1, *supra*. This proceeding takes place pursuant to a state law, Act 341, that did not exist when Case No. U-17032 was decided. Additionally, the PJM tariff required the setting of an SCM, not an SRM.

[9] The parties agree that Consumers has no bilateral contract sales.

sales." MCL 460.6w(3)(b). The plain language of the statute provides no support for Consumers' proposed interpretation.

The Commission notes that Section 6w(3)(a) and (b) differ in that, while (a) relies on "base rates, surcharges, and [PSCR] factors," (b) relies on "projected revenues" net of "projected fuel costs." Thus, (3)(a) refers to embedded costs and (3)(b) refers to forecasted costs. The Commission finds that Energy Michigan is the only party that attempted to calculate the actual amounts associated with the required subtractions under Section 6w(3)(b) in the way that the statute requires. In his revised testimony, Mr. Jennings thoroughly describes how he used the Aurora model to arrive at forecasted amounts reflecting the required deductions. 6 Tr 562-574. Mr. Jennings indicates that he relied on "neutral third party assumptions for some of the variables including load forecasts, gas prices and delivered coal prices." 6 Tr 567. He testifies that for the load growth assumption he relied on MISO's latest electricity demand outlook from the fall of 2016; for the natural gas price he used the New York Mercantile Exchange or NYMEX forward price curve dated June 29, 2017; and for the delivered coal price he used the actual price of consumed coal reported by Consumers in its 2016 Form No. 1 filed with FERC adjusted by current escalations for coal and transportation. The Aurora model was used to develop a generation forecast based on Consumers' owned and purchased power (relying on the original 2016 PSCR plan filing, data from Case No. U-18250, and a list of long-term contracts provided by Consumers). Total fuel costs were also produced by the Aurora model. He calculated the five-year historical average of off-system power sales to Alpena and the five-year historical average of ancillary service sales, also from Consumers' Form No. 1. Exhibits EM-11 through EM-15; 6 Tr 566-573. While the model is admittedly data-intensive, the Commission finds the sources that he used for his forecasts and assumptions to be reliable. The Commission notes that in cross-examination certain units' standings were questioned; however, the results of the analysis were not impacted because those units were not selected for dispatch, making the inclusion of those units irrelevant.[10] 6 Tr 600-602; Exhibits EM-14 and EM-15. Other than the cross-examination discussed, no party disputed the sources of his information. His conclusions were then applied by Mr. Smith.

In Exhibit EM-7, Mr. Smith begins with Consumers' projected total capacity costs of $1,565 million (Exhibits A-2 and A-3), and applies the deductions for 2018 calculated by Mr. Jennings, to arrive at an SRM capacity annual rate for 2018 of $109,714/MW-year, or $300.59/MW-day under Section 6w(3). The Commission finds Mr. Smith's calculations, based on the embedded cost information supplied by Consumers and the forecasted amounts supplied by Mr. Jennings, to be credible and consistent with the requirements of Section 6w.[11] Mr. Smith begins with the total capacity costs supplied by Consumers of $1,565 million. Mr. Jennings calculated energy market sales of $1,023 million, off-system energy sales of $12 million, and ancillary service sales of $25 million, offset by related fuel costs of $409 million, for a total of $651 million to be deducted from the total capacity costs per Section 6w(3)(b). Mr. Smith arrives at a net capacity cost of $914 million. He relied on Consumers' 2016 SEC Form 10-k for a total capacity supply of 8,331 MW. Dividing the cost by the total capacity produces $109,714/MW-year, or $300.59/MW-day. This approach relies on the historical embedded cost of service method that the Commission traditionally uses, and comports with Section 6w, MCL 460.11, and Commission precedent. It

[10] The Commission notes that both Ms. Walz and Mr. Jennings excluded the Palisades PPA from their calculations, because, at the time their evidence was filed, Palisades was expected to close in 2018. 5 Tr 392-393; 6 Tr 568, 575-576. While the Palisades plant is now expected to remain open, the Commission finds that, because the plant was excluded under both Section 6w(a) and Section 6w(b), their evidence can continue to provide a basis for calculating the capacity charge.

[11] The Commission acknowledges that this is not the method that Energy Michigan advocates.

results in a capacity charge that is only about 15% above MISO CONE for 2016, which represents the estimated cost of building a new gas-fired CT (viewed as the lowest cost, supply-side capacity resource).

In addition to selecting this methodology because it is the most consistent with the plain reading of the law, the methodology is also logical. The methodology as set forth in the statute and adopted by the Commission in this order attempts to isolate the production costs associated with capacity by deducting revenues from energy sales (net of fuel costs). There is evidence discussing how certain production costs are attributable to producing lower cost energy, but it can be difficult to measure this “energy value” for each generating unit and the overall portfolio over time. 6 Tr 753-755. Yet it is well established in utility resource planning that it can be cost effective (depending on the utility’s overall capacity and energy needs) to build a generator that has higher fixed costs in order to produce energy at a lower cost. And generally speaking, generators with lower energy costs would produce higher net revenue from sales in the market. Thus, the energy sales in the market, less fuel costs, represent in some fashion the energy value of the generation portfolio. It serves as a proxy for determining how to separate out the energy costs from the overall production costs to arrive at a capacity-only cost. The fact that the utility is buying some or all of its energy in the same wholesale market to serve its own customers is immaterial. One could apply this same approach if the generation source had no customers (thus, no energy market purchases) in order to arrive at an estimate of the generator’s capacity cost. Some parties, including the Staff, suggest a bottom-up approach to identify capacity-only resource in order to set the state reliability charge. The end result is similar in terms of the overall charge, but given the statutory guidance in Section 6w(3) the Commission is persuaded by the top-down, embedded cost methodology as presented by Mr. Jennings and Mr. Smith.

For all of these reasons, the Commission finds that the methodology for establishing the state reliability charge supported by the Jennings and Smith testimony is reasonable, appropriate, and consistent with Section 6w. The Commission further finds that the Staff's proposed revenue requirement allocation based on use of 4 CP is the most appropriate as it is the only one supported on the record.

Rate Design

The Commission agrees with the Staff and ABATE that the results of the allocation of capacity related costs in the COSS should be used to set a separate charge for each customer class, and that the SRM charge should not result in alteration of the spread of the total revenue requirement among rate classes. The Commission finds that Consumers' rate design proposal for a year round charge comes the closest to mirroring the currently-approved rate design set in Case No. U-17990 and the Commission adopts the utility's proposal, with the modifications necessary to prevent any shift among the amounts collected from each rate class and to ensure that no less revenue is collected through demand charges than is collected in current rates. Consumers indicates that it designed a rate for each rate class that collects the allocated capacity costs based on the customers' sales determinants, and ensures that any ROA customer subject to the charge will pay the same as a comparable full service customer. 5 Tr 371-376; Exhibit A-4. Capacity is provided year round through service provided by Consumers' entire owned and purchased generation portfolio. Full service customers currently pay for capacity year round and the Commission finds that this billing construct should remain applicable to all customers who are subject to the capacity charge. While the Commission appreciates the Staff's rate design proposal to better align rates to reflect how capacity costs are incurred (primarily to cover the summer peak), this is not the proceeding to modify rate design given the complexity of other issues. This issue could be revisited, as appropriate, in a future rate case.

Section 6w(3) provides that no new capacity charge may be required to be paid before June 1, 2018. The Commission finds that the capacity charge approved by this order shall apply to bundled customers as of that date. Attachment A to this order reflects the application of the decisions made herein to Consumers' proposed rate design. Attachment A is merely illustrative, because Consumers' pending rate case, Case No. U-18322, will have been completed prior to June 1, 2018, and new costs and a new rate design will apply to the capacity charge. Attachment A should provide guidance for the utility when the applicable rate design and tariff sheets are required to be filed.

Section 6w(4) provides for a true-up of "the difference between the projected net revenues described in subsection (3) and the actual net revenues reflected in the capacity charge." Projected net revenues are addressed in Section 6w(3)(b). Thus, the Commission agrees with the parties that the reconciliation required under Section 6w(4) is limited to the amounts forecasted under Section 6w(3)(b), and should occur in the annual PSCR reconciliation – a currently-existing proceeding that is designed for this precise type of true-up and which already calls for the filing of much of the relevant information in that docket, since fuel costs, market revenues, sales and PPA expenses are reconciled in PSCR cases. Any difference will be included in the following year's capacity charge. The Commission does not find, at this time, that the creation of a standalone proceeding is necessary. Among the options of general rate cases (which require a decision within ten months), PSCR plan cases, and PSCR reconciliations, the Commission believes that the annual review of the SRM charge required under Section 6w(5) will be accomplished for Consumers. For this reason, the Commission also rejects ABATE's proposal for an update of the charge. If, after more experience with implementation of Section 6w, the Commission finds it necessary, the question of a separate proceeding, even in years when a rate case and a PSCR reconciliation are taking place, may be revisited. In the meantime, the Commission finds that a standalone proceeding need only be commenced if no annual review will take place in a rate case or PSCR case.

The Commission agrees with the Staff that it is not necessary to split the PSCR factor into capacity and non-capacity components. 6 Tr 761-762. Due to the fact that PSCR related rates are already split into a base rate component and a factor component (and the factor itself is subject to movement during the course of the PSCR year), dividing PSCR factor costs seems subject to a high degree of uncertainty and adds an unnecessary level of complexity. The Commission agrees with the Staff's suggestion to effectively assume all capacity costs are in the base. Staff's initial brief, pp. 33-34. This simplifies the process but still ensures equitable treatment between full service and ROA customers because capacity cost increases will be recognized in the base in subsequent rate cases or other SRM charge review cases, and the base is used to set the capacity charge applicable to all customers.

<u>Application of the Capacity Charge to Choice Customers</u>

Several intervenors argue that the capacity charge should be levied on the AES and not on choice customers. The Commission finds that a capacity charge shall be levied on the ROA customer receiving the capacity service from the incumbent utility for several reasons. As these intervenors are well aware, Section 201(b)(1) of the Federal Power Act (FPA), 16 USC § 824(b)(1), vests FERC with jurisdiction over wholesale sales of electric energy in interstate commerce; and Section 205(a) of the FPA, 16 USC § 824d(a), confers on FERC the responsibility to ensure that wholesale power sales rates and charges are just and reasonable. *See, Mississippi Power & Light Co v Mississippi ex rel Moore*, 487 US 354, 371; 108 SCt 2428; 101 LEd2d 322

(1988). AESs resell their product to ROA customers. Thus, were the Commission to, pursuant to Section 6w, set a capacity charge to be paid by AESs to incumbent utilities, Section 6w would be a legal nullity subject to immediate federal preemption. The Commission finds it disingenuous to posit that the Legislature mistakenly engaged in the pointless enactment of a statute requiring the Commission to set a wholesale rate for AESs, when other aspects of Section 6w reveal that the Legislature well understood the role that FERC plays in the MISO process.

Rules of statutory construction provide that the "words used in the statute are the most reliable indicator of the Legislature's intent and should be interpreted on the basis of their ordinary meaning and the context within which they are used." *Dep't of Environmental Quality v Worth Twp*, 491 Mich 227, 237-238; 814 NW2d 646 (2012). Effect should be given to every phrase, clause, and word in the statute "read and understood in its grammatical context," and the statute "must be read as a whole unless something different was clearly intended." *Id.* The Commission "must give effect to every word, phrase, and clause in a statute and avoid an interpretation that would render any part of the statute surplusage or nugatory." *Johnson v Recca*, 492 Mich 169, 177; 821 NW2d 520 (2012). Clearly, this concept extends to an entire statute. The Commission has no jurisdiction over wholesale power sales – a fact that the Commission feels justified in believing the Michigan Legislature to be aware of.

As the rules of statutory construction make clear, the words used in the statute are the most reliable indicator of the intended meaning. The specific language of Section 6w is instructive. Everywhere that the charge is referred to, the Commission is instructed to apply it to full service or AES "load." Section 6w(3) provides "the charge must be applied to alternative electric load," and the Commission "shall ensure that the resulting capacity charge does not differ for full service load and alternative electric load." Section 6w(6) provides that the charge "must be paid for the portion of [the utility's] load taking service from the AES not covered by capacity." Section 6w(7) provides that the incumbent utility "shall provide capacity to meet the capacity obligation for the portion of that load taking service from an AES." And Section 6w(8)(b)(i) provides that the Commission shall "[f]or alternative electric load, require the payment of a capacity charge that is determined, assessed, and applied in the same manner as under subsection (3) for that portion of the load not covered as set forth" in subsections (6) and (7).

"Load" can be ambiguous, but is generally understood to mean power consumed, as by a device or circuit.[12] "To different people in different departments of a utility, load may mean different things; such as active power (in kW), apparent power (in kVA [kilo-volt-ampere]), energy (in kWh), current (in ampere), voltage (in volt), and even resistance (in ohm). In load forecasting, load usually refers to demand (in kW) or energy (in kWh)."[13] What each of these definitions has in common is that they relate to the use of power by the end-user. In addition to Section 6w, "load" is frequently referred to in the choice law, 2001 PA 141 (Act 141), MCL 460.10 et seq., as well. For example, Section 10a(1)(b) of Act 141 requires the Commission to "allocate the amount of load that will be allowed to be served by alternative electric suppliers;" and Section 10bb(3) provides that "'aggregation' means the combining of electric loads of multiple retail customers or a single customer with multiple sites." It is important to remember that the capacity charge is paid by both full service and choice customers. Each use of "load" in both the choice law and in Section 6w refers to power that is consumed by end-users and could often be replaced with the word "customers;" but none of these references to "load" make sense

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[12] Merriam-Webster Third New International Dictionary (1st ed.).

[13] Hong, T., *et al*, Load Forecasting Case Study, January 15, 2015, NARUC and Eastern Interconnection States' Planning Council, p. 9-2.

when replaced with "alternative electric supplier." Nothing may be read into a statute that is not "within the manifest intent of the Legislature as derived from the words of the statute itself." *Covenant Medical Ctr v State Farm Mut Automobile Ins Co,* 500 Mich 191, ___; 895 NW2d 490, 495 (2017) (citation omitted). The Commission finds that to levy the capacity charge on an AES would require reading into Section 6w something that is not there.

In making their argument, the intervenors emphasize the wording of Section 6w(6), which requires an "electric provider" that has previously made a satisfactory demonstration to give notice to the Commission if it expects to be unable to make its demonstration in the next (four-year-out) planning year "and instead expects to pay a capacity charge." The Commission finds that this sentence must be read in the context of Section 6w as a whole. *Johnson*, 492 Mich at 177. There is no entity that could give such notice other than the AES, since only the AES knows whether it intends to provide its customers with sufficient capacity or intends to provide something less. ROA customers are incapable of providing such notice, even though they are the parties that will be paying the charge.

The Legislature has chosen to make incumbent utilities (which are subject to rate regulation) the capacity suppliers of last resort under Section 6w(7).[14] The capacity charge is a retail rate, designed to recover the incumbent utility's cost of providing capacity service, to whatever type of customer load – bundled or choice. The Commission has full discretionary authority to set just and reasonable rates, which are based on a determination of the reasonable costs of doing business

[14] The Commission rejects Energy Michigan's assertion that the capacity charge somehow violates MISO's tariff by allowing for the transfer of the PRMR obligation. MISO's Module E-1, 32.0.0, 69A.1.1.1, allows for the transfer of the capacity obligation where it specifies that the "LSE that is the provider of last resort ("POLR") for the [electric distribution company] EDC area in question will have the obligation to procure capacity for the required PRMR for the remaining Demand" for its area.

and what charges and expenses to allow as costs of operation. MCL 460.6; *Detroit Edison Co v Public Service Comm*, 127 Mich App 499, 524; 342 NW2d 273 (1983). The service is provided by the utility, and thus must be billed by the utility. And this service to provide long-term resource adequacy as a default provider is essential to ensuring reliable electric service for all customers. *See*, MCL 460.10(a), (c); 460.10q(2)(a); 460.10b(3). Consumers correctly notes that AESs remain free to contract with their customers in whatever way they wish to mitigate the effect of the capacity charge, when capacity must be supplied by the incumbent utility because the AES has failed to make a satisfactory demonstration. And the Staff correctly points out that if the service were billed to the AES, there would be no way for the Commission to carry out the mandate that the capacity charge paid by bundled load and choice load must not differ, nor any way for the Commission to ensure that the cost to the customer reflects the cost to serve that customer under MCL 460.11.

Finally, the Commission wishes to elaborate on how Section 6w and the choice law are intended to work together. In the two decades since varying forms of retail competition were implemented in states across the country, different models for continued state oversight over the supply and delivery of electricity have emerged. Provision of electricity to end-use customers is comprised of multiple components, including power supply service (e.g., energy and capacity), wires service (e.g., distribution), and other functions associated with the use of electricity, such as energy efficiency programs, providing bill payment assistance to low-income customers, and collection of funds to use for decommissioning of nuclear generating facilities. Even with the advent of retail competition, many states continued to set prices for “default” electricity service, to ensure the availability of reliable power to end-users and meet other objectives including, in some cases, state policy goals. Under Act 141, Michigan left this default service responsibility with the incumbent utility, and the Commission retained jurisdiction to regulate the utility's rates for electric generation services. The regulated utility was expected to compete with the licensed AESs in the provision of power supply service while at the same time providing wires service, as well as functions like energy efficiency programs, to all end-use customers. In other states with restructured electricity markets, default power supply services were provided by either the incumbent utility or another entity selected through a competitive bidding process or other mechanism. Some states that required the incumbent utility to fully divest its generation as a competitive function still facilitated and approved procurement activities for energy or capacity to reliably serve some or all end-use customers under their retail choice model (or the transition thereto).

The purchase of energy, capacity, or both, from a third party by the load serving entity, whether it is a vertically integrated utility under state rate regulation, or a competitive retailer or default service provider under a retail choice construct, is a wholesale purchase. But charging customers for the provision of electricity supply and other services associated with customers' electricity use is decidedly a retail activity. States have defined what types of entities provide these services with varying degrees of specificity. In some states, it is only the regulated incumbent utility providing power supply, wires service, and other functions, costs for all of which are recovered through retail rates. In states with retail competition, some of these services, such as power supply, are provided by a third party under market-based prices, or as part of regulated default service, with the wires and other functions associated with electricity use collected through nonbypassable charges flowing through to the customer (either directly or in combination with the energy supply portion).

The provision of power supply service includes both capacity and energy components, among others. Providing long-term "capacity service" to customers to ensure future resource adequacy and provide reasonable assurance that energy will be actually available at any given moment (particularly peak periods) is related to, but notably distinct from, supplying only "energy." These two products or services – energy and capacity – are distinguished from one another in many wholesale contractual arrangements, such as PPAs and in long-term resource planning. They are measured differently as well – kW versus kWh. The costs to provide capacity and energy are allocated to, and collected from, end-use customers differently through conventional cost allocation and rate design methodologies. And like other services, such as energy efficiency, costs for which are recovered through nonbypassable retail charges assessed to end-use customers, the capacity charge under Section 6w is set by the state as a retail charge assessed to retail customers. This is an acknowledgment that Section 6w creates a new category of default service, namely, the provision of capacity service to choice customers whose energy providers do not secure long-term capacity. The capacity charge established under Section 6w is intended to compensate the default supplier (i.e., the incumbent utility) for providing long-term capacity to customers, including customers of energy providers who supply energy but not long-term capacity. This is just one of many services associated with retail electric service that flows through to end-use customers as a retail charge.

The Commission notes that under Section 6w, the same charge applies to "load" whether it is bundled (receiving all services from the incumbent utility) or unbundled (receiving energy service from an AES that has chosen not to provide long-term capacity). And like many states that designated either the incumbent utility or another entity to provide certain default services, Michigan is certainly within its rights to declare that the rate-regulated incumbent utility, certificated by the Commission to serve a specific service area, shall provide this critical long-term reliability service to designated customers. Of course, with this statutorily-mandated assignment of responsibility for the planning and provision of long-term capacity supplies comes the ability for the utility to charge applicable end-use customers taking this particular service from the utility. Supplying long-term capacity is as fundamental to ensuring electric reliability as maintaining the distribution system or other critical functions of the utility for which it is compensated by customers using the service.

<u>ROA Billing and Choice Cap Mechanics</u>

The Commission rejects Consumers' first-in/last-out ROA billing proposition as patently discriminatory. The utility has indicated that, with time and resources, pro rata billing among all affected ROA customers could be accomplished. The Commission directs Consumers to commence the activities necessary to achieve pro rata billing of the capacity charge, should it be imposed on any ROA customers.

The Commission also rejects Consumers' proposal to lower the 10% choice cap. Nothing in Section 6w provides support for such a scheme, while Section 10a(1)(a), (g), and (i) of Act 141 is clear that the Commission shall issue orders providing that "no more than 10% of an electric utility's average weather-adjusted retail sales for the preceding calendar year" may take service from an AES; that "an electric utility shall add a new customer to the queue if the customer's prospective [AES] submits an enrollment request to the electric utility;" and that "if the prospective [AES] of a customer next on the queue" is notified "that less than 10% of an electric utility's average weather-adjusted retail sales for the preceding calendar year are taking service from an [AES]" and the electricity is available, then "the customer may take service from an [AES]." The choice program, including the return to service provisions, will continue to be administered in the same way that it is currently administered. *See*, April 28, May 11, and June 15, 2017 orders in Case No. U-15801. If a capacity charge is levied on an ROA customer that later returns to full service during the year in which the charge is imposed, that customer will commence paying whatever ongoing capacity charge is applicable to full service customers and their load will no longer count toward the 10% cap.

THEREFORE, IT IS ORDERED that:

A. If a state reliability mechanism capacity charge is levied on retail open access customers at the conclusion of a show cause proceeding for planning year 2018-2021 it shall be for the first four consecutive planning years and any charge levied at the conclusion of a show cause proceeding shall be levied and applicable for a single year.

B. Beginning June 1, 2018, Consumers Energy Company shall implement a state reliability mechanism capacity charge of $109,714 per megawatt-year, or $300.59 per megawatt-day, for full service customers, using Consumers Energy Company's proposed year-round rate design as modified by this order, illustrated in Attachment A to this order. Within 30 days of the issuance of the final order in Case No. U-18322, Consumers Energy Company shall file tariff sheets substantially similar to those contained in Attachment A. Due to the size of Attachment A, it is not physically attached to the original order contained in the official docket or paper copies of this order, but is electronically appended to this order, which is available on the Commission's website.

C. In Consumers Energy Company's annual power supply cost recovery reconciliation proceeding the amounts forecasted pursuant to MCL 460.6w(3)(b) shall be reconciled against actual amounts, consistent with the requirements of MCL 460.6w(4), as a separate reconciliation.

D. If an alternative electric supplier operating in Consumers Energy Company's service territory fails to make a satisfactory demonstration regarding its forward capacity obligations pursuant to MCL 460.6w(8), the resulting state reliability mechanism capacity charge shall be levied by Consumers Energy Company on the retail open access customers of that alternative electric supplier on a pro rata basis.

E. Consumers Energy Company is directed to file a standalone contested case for the annual review of its state reliability mechanism capacity charge by April 1, 2018, and annually thereafter, unless the utility expects that the annual review will be taking place in a rate case or power supply cost recovery case that will conclude by December 1 of each year. If the utility does not file a standalone contested case by April 1, 2018, it shall notify the Commission in this docket of the expected approval path and timing for the annual review of the state reliability mechanism capacity charge.

The Commission reserves jurisdiction and may issue further orders as necessary.

Any party desiring to appeal this order must do so in the appropriate court within 30 days after issuance and notice of this order, pursuant to MCL 462.26. To comply with the Michigan Rules of Court's requirement to notify the Commission of an appeal, appellants shall send required notices to both the Commission's Executive Secretary and to the Commission's Legal Counsel. Electronic notifications should be sent to the Executive Secretary at mpscedockets@michigan.gov and to the Michigan Department of the Attorney General - Public Service Division at pungp1@michigan.gov. In lieu of electronic submissions, paper copies of such notifications may be sent to the Executive Secretary and the Attorney General - Public Service Division at 7109 W. Saginaw Hwy., Lansing, MI 48917.

MICHIGAN PUBLIC SERVICE COMMISSION

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Sally A. Talberg, Chairman

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Norman J. Saari, Commissioner

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Rachael A. Eubanks, Commissioner

By its action of November 21, 2017.

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Kavita Kale, Executive Secretary

M.P.S.C. No. 13 - Electric
Consumers Energy Company **Sheet No. D-9.00**

RESIDENTIAL SERVICE SECONDARY RATE RS

Availability:

Subject to any restrictions, this rate is available to any customer desiring electric service for any usual residential use in: (i) private family dwellings; (ii) tourist homes, rooming houses, dormitories, nursing homes and other similarly occupied buildings containing sleeping accommodations for up to six persons; or (iii) existing multifamily dwellings containing up to four households served through a single meter. Service for single-phase or three-phase equipment may be included under this rate, provided the individual capacity of such equipment does not exceed 3 hp or 3 kW, nor does the total connected load of the home exceed 10 kW, without the specific consent of the Company.

This rate is not available for: (i) resale purposes; (ii) multifamily dwellings containing more than four living units served through a single meter; (iii) tourist homes, rooming houses, dormitories, nursing homes and similarly occupied buildings containing sleeping accommodations for more than six persons; or (iv) any other Non-Residential usage.

Residences in conjunction with commercial or industrial enterprises and mobile home parks may take service on this rate only under the Rules and Regulations contained in the Company's Electric Rate Book.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

The Company will schedule meter readings on a monthly basis and attempt to obtain an actual meter reading for all tourist and/or occasional residence customers at intervals of not more than six months.

Monthly Rate:

Power Supply Charges: **These charges are applicable to Full Service customers.**

Energy Charge:

Non-Capacity	*Capacity*	*Total*	
$*0.061937*	$*0.031947*	$0.093884	per kWh for the first 600 kWh per month during the billing months of June-September
$*0.083624*	$*0.043133*	$0.126757	per kWh for all kWh over 600 kWh per month during the billing months of June-September
$*0.061937*	$*0.031947*	$0.093884	per kWh for all kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

Delivery Charges: **These charges are applicable to Full Service and Retail Open Access customers.**

System Access Charge:	$7.00	per customer per month
Distribution Charge:	$0.047220	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

(Continued on Sheet No. D-10.00)

M.P.S.C. No. 13 - Electric
Consumers Energy Company **Sheet No. D-13.01**

RESIDENTIAL DYNAMIC PRICING PROGRAM

(Continued From Sheet No. D-13.00)

Monthly Rate:

Option 1 - Residential Dynamic Pricing Rate RDP:

Power Supply Charges: **These charges are applicable to Full Service customers.**

Energy Charge:

	Non-Capacity	*Capacity*	*Total*	
Off-Peak – Summer	*$0.049526*	*$0.028119*	$0.077645	per kWh for all Off-Peak kWh during the billing months of June-September
Mid-Peak – Summer	*$0.067469*	*$0.038307*	$0.105776	per kWh for all Mid-Peak kWh during the billing months of June-September
On-Peak – Summer	*$0.091465*	*$0.051931*	$0.143396	per kWh for all On-Peak kWh during the billing months of June-September
Off-Peak – Winter	*$0.049526*	*$0.028119*	$0.077645	per kWh for all Off-Peak kWh during the billing months of October-May
On-Peak – Winter	*$0.061645*	*$0.035000*	$0.096645	per kWh for all On-Peak kWh during the billing months of October-May
Critical Peak Event	*$0.627463*	*$0.322537*	$0.950000	per kWh during a critical peak event between June 1 and September 30

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00

Delivery Charges: **These charges are applicable to Full Service Customers.**

System Access Charge:	$7.00	per customer per month
Distribution Charge:	$0.047220	per kWh for all kWh for a Full Service Customer

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

Option 2 - Residential Dynamic Pricing Rewards Rate RDPR:

Power Supply Charges: **These charges are applicable to Full Service Customers.**

Energy Charge:

	Non-Capacity	*Capacity*	*Total*	
Off-Peak-Summer	*$0.054689*	*$0.028119*	$0.082808	per kWh for all Off-Peak kWh during the billing months of June-September
Mid-Peak-Summer	*$0.074502*	*$0.038307*	$0.112809	per kWh for all Mid-Peak kWh during the billing months of June-September
On-Peak-Summer	*$0.101000*	*$0.051931*	$0.152931	per kWh for all On-Peak kWh during the billing months of June-September
Off-Peak-Winter	*$0.054689*	*$0.028119*	$0.082808	per kWh for all Off-Peak kWh during the billing months of October-May
On-Peak -Winter	*$0.068071*	*$0.035000*	$0.103071	per kWh for all On-Peak kWh during the billing months of October-May
Critical Peak Reward	*$(0.627463)*	*$(0.322537)*	$(0.950000)	per kWh during a critical peak event between June 1 and September 30

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

(**Continued on Sheet No. D-13.02)**

EXPERIMENTAL RESIDENTIAL PLUG-IN ELECTRIC VEHICLE CHARGING PROGRAM

Availability:

The Experimental Residential Plug-In Electric Vehicle Charging Program is a voluntary pilot available to Full Service residential customers. Upon enrollment of the customer in the program, the customer may take service under one of the following options as applicable:

Option 1 - Residential Home and Plug-in Electric Vehicle Time-of-Day Rate (REV-1) – Level 1 or Level 2 Charging of an electric vehicle combined with household electric usage such as space conditioning, cooking, water heating, refrigeration, clothes drying, incineration or lighting based upon on-peak, mid-peak and off-peak periods and through a single meter.

Option 2 - Residential Plug-In Electric Vehicle Only Time-of-Day Rate (REV-2) – Level 2 Charging of the electric vehicle based upon on-peak, mid-peak and off-peak periods through a separate meter. Electric usage for the household will be billed under the RS or RT Rate Schedule.

"Level 1 Charging" is defined as voltage connection of 120 volts and a maximum load of 12 amperes or 1.4 kVA.

"Level 2 Charging" is defined as voltage connection of either 240 volts or 208 volts and a maximum load of 32 amperes or 7.7 kVA at 240 volts or 6.7 kVA at 208 volts.

"Electric Vehicle Supply Equipment (EVSE)" is defined as the conductors, including the ungrounded, grounded and equipment grounding conductors, the electric vehicle connectors, attachment plugs, and all other fittings, devices, power outlets, or apparatus installed specifically for the purpose of delivering energy from the premise wiring to the electric vehicle.

Vehicles shall be registered and operable on public highways in the State of Michigan to qualify for this rate. Low-speed electric vehicles including golf carts are not eligible to take service under this rate even if licensed to operate on public streets. The customer may be required to provide proof of registration of the electric vehicle to qualify for program.

The total connected load of the home including the electric vehicle charging shall not exceed 10 kW, without the specific consent of the Company.

Customers shall not back-feed or transmit stored energy from the electric vehicle's battery to the Company's distribution system.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service.

Monthly Rate:

Option 1 – REV-1:

Power Supply Charges: **These charges are applicable to Full Service customers.**

Energy Charge:

	Non-Capacity	*Capacity*	*Total*	
Off-Peak – Summer	*$0.054689*	*$0.028119*	$0.082808	per kWh for all Off-Peak kWh during the billing months of June-September
Mid-Peak – Summer	*$0.074502*	*$0.038307*	$0.112809	per kWh for all Mid-Peak kWh during the billing months of June-September
On-Peak – Summer	*$0.101000*	*$0.051931*	$0.152931	per kWh for all On-Peak kWh during the billing months of June-September
Off-Peak – Winter	*$0.054689*	*$0.028119*	$0.082808	per kWh for all Off-Peak kWh during the billing months of October-May
On-Peak – Winter	*$0.068071*	*$0.035000*	$0.103071	per kWh for all On-Peak kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

(Continued on Sheet No. D-13.20)

EXPERIMENTAL RESIDENTIAL PLUG-IN ELECTRIC VEHICLE CHARGING PROGRAM

(Continued From Sheet No. D-13.20)

Monthly Rate (Contd)

Option 2 - REV-2:

Power Supply Charges: **These charges are applicable to Full Service customers.**

Energy Charge:

	Non-Capacity	*Capacity*	*Total*	
Off-Peak – Summer	*$0.054689*	*$0.028119*	$0.082808	per kWh for all Off-Peak kWh during the billing months of June-September
Mid-Peak – Summer	*$0.074502*	*$0.038307*	$0.112809	per kWh for all Mid-Peak kWh during the billing months of June-September
On-Peak – Summer	*$0.101000*	*$0.051931*	$0.152931	per kWh for all On-Peak kWh during the billing months of June-September
Off-Peak – Winter	*$0.054689*	*$0.028119*	$0.082808	per kWh for all Off-Peak kWh during the billing months of October-May
On-Peak – Winter	*$0.068071*	*$0.035000*	$0.103071	per kWh for all On-Peak kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

Delivery Charges: **These charges are applicable to Full Service and Retail Open Access customers**

Distribution Charge: $0.047220 for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10. The REP Surcharge shown on Sheet No. D-2.10 shall not apply.

General Terms:

These rates are subject to all general terms and conditions shown on Sheet No. D-1.00.

(Continued on Sheet No. D-13.30)

RESIDENTIAL SERVICE TIME-OF-DAY SECONDARY RATE RT

Availability:

Subject to any restrictions, this rate is available to any residential customer desiring electric service who chooses to have their electric consumption metered based upon on-peak and off-peak periods. In addition, this rate is available to customers desiring electric service for electric vehicle battery charging where such service is in addition to all other household requirements. Battery charging service is limited to four-wheel vehicles licensed for operation on public streets and highways. Service for single-phase or three-phase equipment may be included under this rate, provided the individual capacity of such equipment does not exceed 3 hp or 3 kW, nor does the total connected load of the home exceed 10 kW, without the specific consent of the Company.

Service under this rate is limited to 10,000 customers.

This rate is not available for resale purposes or for any Non-Residential usage.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Monthly Rate:

Power Supply Charges: **These charges are applicable to Full Service Customers.**

Energy Charge:

	Non-Capacity	*Capacity*	*Total*	
On-Peak-Summer	*$0.081641*	*$0.030065*	$0.111706	per kWh for all On-Peak kWh during the billing months of June-September
Off-Peak-Summer	*$0.055111*	*$0.020295*	$0.075406	per kWh for all Off-Peak kWh during the billing months of June-September
On-Peak-Winter	*$0.067017*	*$0.024679*	$0.091696	per kWh for all On-Peak kWh during the billing months of October-May
Off-Peak -Winter	*$0.057539*	*$0.021829*	$0.079368	per kWh for all Off-Peak kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

Delivery Charges: **These charges are applicable to Full Service and Retail Open Access Customers.**

System Access Charge:	$7.00	per customer per month
Distribution Charge:	$0.047220	per kWh for all kWh for a Full Service Customer

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10

Income Assistance Service Provision (RIA):

When service is supplied to a Principal Residence Customer, where the household receives a Home Heating Credit (HHC) in the State of Michigan, a credit shall be applied during all billing months. For an income assistance customer to qualify for this credit the Company shall require annual evidence of the HHC energy draft or warrant. The customer may also qualify for this credit by meeting the requirements under Rule B2, Consumer Standards and Billing Practices for Electric and Gas Residential Customers, R 460.102, Definitions. Confirmation shall be required by an authorized State or Federal agency to verify that the customer's total household income does not exceed 150% of the Federal poverty level.

The monthly credit for the residential Income Assistance Service Provision shall be applied as follows:

Delivery Charges: **These charges are applicable to Full Service and Retail Open Access Customers.**

Income Assistance Credit: $(7.00) per customer per month

This credit shall not be taken in conjunction with a credit for the Senior Citizen Service Provision (RSC).

(Continued on Sheet No. D-15.00)

GENERAL SERVICE SECONDARY RATE GS

Availability:

Subject to any restrictions, this rate is available to any general use customer, political subdivision or agency of the State of Michigan, either acting separately or in combinations permitted under the laws of this state, desiring Secondary Voltage service for any of the following: (i) standard secondary service, (ii) public potable water pumping and/or waste water system(s), or (iii) resale purposes. This rate is also available for service to any Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is not available for: (i) private family dwellings, (ii) lighting service except for private streets, mobile home parks or service to temporary lighting installations, (iii) heating water for industrial processing, (iv) resale for lighting service, or (v) new or expanded service for resale to residential customers. Unmetered Billboard Service is not available to Retail Open Access service.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Three-phase, 3-wire service requires that the customer furnishes all transformation facilities required for single-phase load and so arranges the load as to avoid excessive unbalance of the three-phase load. When the service is single-phase, or 4-wire, three-phase, the single-phase individual motor capacity shall not exceed 3 hp, nor the total single-phase motor capacity of 10 hp, without the specific consent of the Company.

Where the Company elects to measure the service on the Primary side of the transformers, 3% shall be deducted for billing purposes from the energy measurements thus made. Where the Company elected to provide a Primary Rate Customer one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer, 3% shall not be deducted for billing purposes from the energy measurements thus made.

Monthly Rate:

Power Supply Charges: **These charges are applicable to Full Service customers.**

Energy Charge:

Non-Capacity	*Capacity*	*Total*	
$0.063332	*$0.030663*	$0.093995	per kWh for all kWh during the billing months of June-September
$0.061951	*$0.029994*	$0.091945	per kWh for all kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

Delivery Charges: **These charges are applicable to Full Service and Retail Open Access customers.**

System Access Charge:	$20.00	per customer per month
Distribution Charge:	$0.042154	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

Billboard Service Provision:

Monthly kWh shall be determined by multiplying the total connected load in kW (including the lamps, ballasts, transformers, amplifiers, and control devices) times 730 hours. The kWh for cyclical devices shall be adjusted for the average number of hours used.

(Continued on Sheet No. D-19.00)

GENERAL SERVICE SECONDARY TIME-OF-USE RATE GSTU

Availability

Subject to any restrictions, General Service Secondary Time-of-Use Rate GSTU is available to any Full Service Customer taking service at the Company's Secondary Voltage level with advanced metering infrastructure and supporting critical systems.

This rate is not available for: (i) private family dwellings, (ii) lighting service except for private streets, mobile home parks or service to temporary lighting installations, (iii) heating water for industrial processing, (iv) resale for lighting service, or (v) new or expanded service for resale to residential customers.

This rate shall not be taken in conjunction with any other Demand Response Program or Net Metering.

Nature of Service

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Three-phase, 3-wire service requires that the customer furnishes all transformation facilities required for single-phase load and so arranges the load as to avoid excessive unbalance of the three-phase load. When the service is single-phase, or 4-wire, three-phase, the single-phase individual motor capacity shall not exceed 3 hp, nor the total single-phase motor capacity of 10 hp, without the specific consent of the Company.

Where the Company elects to measure the service on the Primary side of the transformers, 3% shall be deducted for billing purposes from the energy measurements thus made. Where the Company elected to provide a Primary Rate Customer one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer, 3% shall not be deducted for billing purposes from the energy measurements thus made.

Monthly Rate

Power Supply Charges: **These charges are applicable to Full Service Customers.**

Energy Charge:

	Non-Capacity	*Capacity*	*Total*	
Off-Peak-Summer	*$0.056659*	*$0.027432*	$0.084091	per kWh for all Off-Peak kWh during the billing months of June-September
Mid-Peak-Summer	*$0.080934*	*$0.039185*	$0.120119	per kWh for all Mid-Peak kWh during the billing months of June-September
On-Peak-Summer	*$0.109719*	*$0.053121*	$0.162840	per kWh for all On-Peak kWh during the billing months of June-September
Off-Peak-Winter	*$0.051644*	*$0.025004*	$0.076648	per kWh for all Off-Peak kWh during the billing months of October-May
On-Peak -Winter	*$0.059666*	*$0.028887*	$0.088553	per kWh for all On-Peak kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

Delivery Charges: **These charges are applicable to Full Service Customers.**

System Access Charge:	$20.00	per customer per month
Distribution Charge:	$0.042154	per kWh for all kWh for a Full Service Customer

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10

(Continued on Sheet No. D-21.20)

GENERAL SERVICE SECONDARY DEMAND RATE GSD

Availability:

Subject to any restrictions, this rate is available to any customer desiring Secondary Voltage service, either for general use or resale purposes, where the Peak Demand is 5 kW or more. This rate is also available for service to any Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is not available for: (i) private family dwellings, (ii) lighting service, (iii) resale for lighting service, or (iv) new or expanded service for resale to residential customers.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Secondary Voltage service. The Company will determine the particular nature of the voltage in each case.

Three-phase, 3-wire service requires that the customer furnishes all transformation facilities required for single-phase load and so arranges the load as to avoid excessive unbalance of the three-phase load. When the service is single-phase, or 4-wire, three-phase, the single-phase individual motor capacity shall not exceed 3 hp, nor the total single-phase motor capacity of 10 hp, without the specific consent of the Company.

Where the Company elects to measure the service on the Primary side of the transformers, 3% shall be deducted for billing purposes from the demand and energy measurements thus made. Where the Company elected to provide a Primary Rate Customer one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer, 3% shall not be deducted for billing purposes from the energy measurements thus made.

Monthly Rate:

Power Supply Charges: **These charges are applicable to Full Service Customers.**

Capacity:	*$11.84*	per kW for all kW of Peak Demand during the billing months of June-September
	$9.84	per kW for all kW of Peak Demand during the billing months of October-May
Energy Charge:		
	Non-Capacity	
	$0.062194	per kWh for all kWh during the billing months of June September
	$*0.060838*	per kWh for all kWh during the billing months of October-May.

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

Delivery Charges: **These charges are applicable to Full Service and Retail Open Access (ROA) customers.**

System Access Charge:	$30.00	per customer per month
Capacity Charge:	$1.15	per kW for all kW of Peak Demand
Distribution Charge:	$0.030042	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10

(Continued on Sheet No. D-23.00)

GENERAL SERVICE PRIMARY RATE GP

Availability:

Subject to any restrictions, this rate is available to any customer, political subdivision or agency of the State of Michigan, either acting separately or in combinations permitted under the laws of this state, desiring Primary Voltage service for general use or for public potable water pumping and/or waste water system(s).

This rate is available to existing Full Service Customers with an electric generating facility interconnected at a primary voltage level utilizing General Service Primary Rate GP for standby service on or before June 7, 2012. The amount of retail usage shall be determined on an hourly basis. Customers with a generating installation are required to have an Interval Data Meter.

This rate is not available to a Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is not available for lighting service, except for temporary service for lighting installations.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Where service is supplied at a nominal voltage of 25,000 Volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 Volts, 1% shall be deducted for billing purposes, from the energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 Volts, 3% shall be added for billing purposes, to the energy measurements thus made.

Monthly Rate:

Power Supply Charges: **These charges are applicable to Full Service customers.**

Charges for Customer Voltage Level 3 (CVL3)
Energy Charge:

Non-Capacity	*Capacity*	*Total*	
$0.057158	*$0.037038*	$0.094196	per kWh for all kWh during the billing months of June-September
$0.056197	*$0.036014*	$0.092211	per kWh for all kWh during the billing months of October-May

Charges for Customer Voltage Level 2 (CVL2)
Energy Charge:

Non-Capacity	*Capacity*	*Total*	
$0.057158	*$0.038838*	$0.095996	per kWh for all kWh during the billing months of June-September
$0.056197	*$0.037814*	$0.094011	per kWh for all kWh during the billing months of October-May

Charges for Customer Voltage Level 1 (CVL1)
Energy Charge:

Non-Capacity	*Capacity*	*Total*	
$0.057158	*$0.033838*	$0.090996	per kWh for all kWh during the billing months of June-September
$0.056197	*$0.032814*	$0.089011	per kWh for all kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

(Continued on Sheet No. D-27.10)

GENERAL SERVICE PRIMARY DEMAND RATE GPD

Availability:

Subject to any restrictions, this rate is available to any customer desiring Primary Voltage service, either for general use or resale purposes, where the On-Peak Billing Demand is 25 kW or more. This rate is also available to any political subdivision or agency of the State of Michigan, either acting separately or in combinations permitted under the laws of this state, for Primary Voltage service for potable water pumping and/or waste water system(s).

This rate is not available to a Primary Rate Customer where the Company elects to provide one transformation from the available Primary Voltage to another available Primary Voltage desired by the customer.

This rate is also not available for lighting service, for resale for lighting service, or for new or expanded service for resale to residential customers.

Nature of Service:

Service under this rate shall be alternating current, 60-Hertz, single-phase or three-phase (at the Company's option) Primary Voltage service. The Company will determine the particular nature of the voltage in each case.

Where service is supplied at a nominal voltage of 25,000 Volts or less, the customer shall furnish, install and maintain all necessary transforming, controlling and protective equipment.

Where the Company elects to measure the service at a nominal voltage above 25,000 Volts, 1% shall be deducted for billing purposes, from the demand and energy measurements thus made.

Where the Company elects to measure the service at a nominal voltage of less than 2,400 Volts, 3% shall be added for billing purposes, to the demand and energy measurements thus made.

Interval Data Meters are required for service under this rate. Meter reading will be accomplished electronically through telecommunication links or other electronic data methods able to provide the Company with the metering data / billing determinants necessary for billing purposes.

Monthly Rate:

Power Supply Charges: **These charges are applicable to Full Service customers.**

Charges for Customer Voltage Level 3 (CVL3)
Demand Charges:

Capacity	*Non-Capacity*	*Total*	
$12.23	*$10.01*	$22.24	per kW of On-Peak Billing Demand during the billing months of June-September
Capacity	*Non-Capacity*	*Total*	
$11.23	*$10.01*	$21.24	per kW of On-Peak Billing Demand during the billing months of October-May

Energy Charges:

Non-Capacity	
$0.052166	per kWh for all On-Peak kWh during the billing months of June-September
$0.034298	per kWh for all Off-Peak kWh during the billing months of June-September
$0.042407	per kWh for all On-Peak kWh during the billing months of October-May
$0.037135	per kWh for all Off-Peak kWh during the billing months of October-May

Charges for Customer Voltage Level 2 (CVL2)
Demand Charges:

Capacity	*Non-Capacity*	*Total*	
$11.23	*$10.01*	$21.24	per kW of On-Peak Billing Demand during the billing months of June-September
Capacity	*Non-Capacity*	*Total*	
$10.23	*$10.01*	$20.24	per kW of On-Peak Billing Demand during the billing months of October-May

Energy Charges:

Non-Capacity	
$0.053966	per kWh for all On-Peak kWh during the billing months of June-September
$0.036098	per kWh for all Off-Peak kWh during the billing months of June-September
$0.044207	per kWh for all On-Peak kWh during the billing months of October-May
$0.038935	per kWh for all Off-Peak kWh during the billing months of October-May

(Continued on Sheet No. D-31.10)

GENERAL SERVICE PRIMARY DEMAND RATE GPD

(Continued From Sheet No. D-31.00)

Monthly Rate: (Contd)

Power Supply Charges: **These charges are applicable to Full Service customers. (Contd)**

Charges for Customer Voltage Level 1 (CVL1)

Demand Charges:

Capacity	*Non-Capacity*	*Total*	
$10.23	*$10.01*	$20.24	per kW of On-Peak Billing Demand during the billing months of June-September
Capacity	*Non-Capacity*	*Total*	
$9.23	*$10.01*	$19.24	per kW of On-Peak Billing Demand during the billing months of October-May

Energy Charges:

Non-Capacity	
$0.048966	per kWh for all On-Peak kWh during the billing months of June-September
$0.031098	per kWh for all Off-Peak kWh during the billing months of June-September
$0.039207	per kWh for all On-Peak kWh during the billing months of October-May
$0.033935	per kWh for all Off-Peak kWh during the billing months of October-May

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

Delivery Charges: **These charges are applicable to Full Service and Retail Open Access (ROA) customers.**

System Access Charge: $ 200.00 per customer per month

Charges for Customer Voltage Level 3 (CVL3)

Capacity Charge: $ 4.92 per kW of Maximum Demand

Charges for Customer Voltage Level 2 (CVL2)

Capacity Charge: $ 2.07 per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL1)

Capacity Charge: $ 1.14 per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10

Adjustment for Power Factor

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(a) If the average Power Factor during the billing period is .900 or higher, a 0.50% credit will be applied to all metered-based charges, excluding surcharges. This credit shall not in any case be used to reduce the prescribed Minimum Charge.

(b) If the average Power Factor during the billing period is less than .850, a penalty will be applied to all metered-based charges, excluding surcharges, in accordance with the following table:

Power Factor	**Penalty**
0.800 to 0.849	0.50%
0.750 to 0.799	1.00%
0.700 to 0.749	2.00%
Below 0.700	3% first 2 months

Adjustment for Power Factor shall not be applied when the On-Peak Billing Demand is based on 60% of the highest On-Peak Billing Demand created during the preceding bill months of June through September or on a Minimum On-Peak Billing Demand.

(c) A Power Factor less than 0.700 is not permitted and necessary corrective equipment must be installed by the customer. A 15% penalty will be applied to any metered-based charges, excluding surcharges, after two consecutive months below 0.700 Power Factor and will continue as long as the Power Factor remains below 0.700. Once the customer's Power Factor exceeds 0.700, it is necessary to complete two consecutive months below 0.700 before the 15% penalty applies again.

(Continued on Sheet No. D-32.00)

GENERAL SERVICE PRIMARY TIME-OF-USE RATE GPTU

(Continued from Sheet No. D-36.10)

Monthly Rate

Power Supply Charges:

Charges for Customer Voltage Level 3 (CVL3)

Energy Charge:

	Non-Capacity	*Capacity*	*Total*	
Off-Peak-Summer	*$0.052265*	*$0.017584*	$0.069849	per kWh during the calendar months of June-September
Low-Peak-Summer	*$0.069667*	*$0.022373*	$0.092040	per kWh during the calendar months of June-September
Mid-Peak-Summer	*$0.089804*	*$0.027915*	$0.117719	per kWh during the calendar months of June-September
High-Peak-Summer	*$0.102585*	*$0.031432*	$0.134017	per kWh during the calendar months of June-September
Off-Peak - Winter	*$0.055285*	*$0.018415*	$0.073700	per kWh during the calendar months of October - May
Mid-Peak - Winter	*$0.065160*	*$0.021133*	$0.086293	per kWh during the calendar months of October - May
High-Peak - Winter	*$0.067708*	*$0.021833*	$0.089541	per kWh during the calendar months of October - May

Charges for Customer Voltage Level 2 (CVL2)

Energy Charge:

	Non-Capacity	*Capacity*	*Total*	
Off-Peak-Summer	*$0.052265*	*$0.019384*	$0.071649	per kWh during the calendar months of June-September
Low-Peak-Summer	*$0.069667*	*$0.024173*	$0.093840	per kWh during the calendar months of June-September
Mid-Peak-Summer	*$0.089804*	*$0.029715*	$0.119519	per kWh during the calendar months of June-September
High-Peak-Summer	*$0.102585*	*$0.033232*	$0.135817	per kWh during the calendar months of June-September
Off-Peak - Winter	*$0.055285*	*$0.020215*	$0.075500	per kWh during the calendar months of October - May
Mid-Peak - Winter	*$0.065160*	*$0.022933*	$0.088093	per kWh during the calendar months of October - May
High-Peak - Winter	*$0.067708*	*$0.023633*	$0.091341	per kWh during the calendar months of October - May

Charges for Customer Voltage Level 1 (CVL1)

Energy Charge:

	Non-Capacity	*Capacity*	*Total*	
Off-Peak-Summer	*$0.052265*	*$0.014384*	$0.066649	per kWh during the calendar months of June-September
Low-Peak-Summer	*$0.069667*	*$0.019173*	$0.088840	per kWh during the calendar months of June-September
Mid-Peak-Summer	*$0.089804*	*$0.024715*	$0.114519	per kWh during the calendar months of June-September
High-Peak-Summer	*$0.102585*	*$0.028232*	$0.130817	per kWh during the calendar months of June-September
Off-Peak - Winter	*$0.055285*	*$0.015215*	$0.070500	per kWh during the calendar months of October - May
Mid-Peak - Winter	*$0.065160*	*$0.017933*	$0.083093	per kWh during the calendar months of October - May
High-Peak - Winter	*$0.067708*	*$0.018633*	$0.086341	per kWh during the calendar months of October - May

Delivery Charges

System Access Charge:	$200.00	per customer per month
Charges for Customer Voltage Level 3 (CVL 3)		
Capacity Charge:	$4.92	per kW of Maximum Demand
Charges for Customer Voltage Level 2 (CVL 2)		
Capacity Charge:	$2.07	per kW of Maximum Demand
Charges for Customer Voltage Level 1 (CVL 1)		
Capacity Charge:	$1.14	per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

Adjustment for Power Factor

This rate requires a determination of the average Power Factor maintained by the customer during the billing period. Such average Power Factor shall be determined through metering of lagging Kilovar-hours and Kilowatt-hours during the billing period. The calculated ratio of lagging Kilovar-hours to Kilowatt-hours shall then be converted to the average Power Factor for the billing period by using the appropriate conversion factor. Whenever the average Power Factor during the billing period is above .899 or below .850, the customer bill shall be adjusted as follows:

(Continued on Sheet No. D-36.30)

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-37.00)

Schedule of Hours:

The following schedule shall apply Monday through Friday (except holidays designated by the Company):

Summer:	
Off-Peak Hours:	12:00 AM to 6:00 AM and 11:00 PM to 12:00 AM
Low-Peak Hours:	6:00 AM to 2:00 PM and 6:00 PM to 11:00 PM
Mid-Peak Hours:	2:00 PM to 3:00 PM and 5:00 PM to 6:00 PM
High-Peak Hours:	3:00 PM to 5:00 PM
Critical Peak Hours:	3:00 PM to 5:00 PM during a Critical Peak Event
Winter:	
Off-Peak Hours:	12:00 AM to 4:00 PM and 8:00 PM to 12:00 AM
Mid-Peak Hours:	4:00 PM to 5:00 PM and 7:00 PM to 8:00 PM
High-Peak Hours:	5:00 PM to 7:00 PM
Critical Peak Hours:	5:00 PM to 7:00 PM during a Critical Peak Event

Weekends and holidays are off-peak. Designated Company holidays are: New Year's Day - January 1; Memorial Day - Last Monday in May; Independence Day - July 4; Labor Day - First Monday in September; Thanksgiving Day - Fourth Thursday in November; and Christmas Day - December 25. Whenever January 1, July 4, or December 25 fall on Sunday, extended holiday periods such as Monday, January 2, Monday, July 5 and Monday, December 26 shall not be considered as holidays for application of off-peak hours.

Monthly Rate:

Power Supply Charges:

<u>Charges for Customer Voltage Level 3 (CVL3)</u>

Energy Charge:

	Non-Capacity	*Capacity*	*Total*	
Off-Peak-Summer	*$0.033949*	*$0.006400*	$0.040349	per kWh during the calendar months of June-September
Low-Peak-Summer	*$0.045252*	*$0.011195*	$0.056447	per kWh during the calendar months of June-September
Mid-Peak-Summer	*$0.058331*	*$0.016743*	$0.075074	per kWh during the calendar months of June-September
High-Peak-Summer	*$0.066634*	*$0.020264*	$0.086898	per kWh during the calendar months of June-September
Critical Peak-Summer			the greater of either 150% of the High-Peak - Summer Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of June - September	
Off-Peak - Winter	*$0.035910*	*$0.007232*	$0.043142	per kWh during the calendar months of October - May
Mid-Peak - Winter	*$0.042325*	*$0.009953*	$0.052278	per kWh during the calendar months of October - May
High-Peak - Winter	*$0.043979*	*$0.010655*	$0.054634	per kWh during the calendar months of October - May
Critical Peak-Winter			the greater of either 150% of the High-Peak Winter Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of October - May	

(Continued on Sheet No. D-37.20)

ENERGY INTENSIVE PRIMARY RATE EIP

(Continued from Sheet No. D-37.10)

Monthly Rate: (Contd)

Power Supply Charges: (Contd)

Charges for Customer Voltage Level 2 (CVL2)

Energy Charge:

	Non-Capacity	*Capacity*	*Total*	
Off-Peak-Summer	*$0.033949*	*$0.017400*	$0.051349	per kWh during the calendar months of June-September
Low-Peak-Summer	*$0.045252*	*$0.022195*	$0.067447	per kWh during the calendar months of June-September
Mid-Peak-Summer	*$0.058331*	*$0.027743*	$0.086074	per kWh during the calendar months of June-September
High-Peak-Summer	*$0.066634*	*$0.031264*	$0.097898	per kWh during the calendar months of June-September
Critical Peak-Summer			the greater of either 150% of the High-Peak-Summer Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of June-September	
Off-Peak - Winter	*$0.035910*	*$0.018232*	$0.054142	per kWh during the calendar months of October - May
Mid-Peak - Winter	*$0.042325*	*$0.020953*	$0.063278	per kWh during the calendar months of October - May
High-Peak - Winter	*$0.043979*	*$0.021655*	$0.065634	per kWh during the calendar months of October - May
Critical Peak-Winter			the greater of either 150% of the High-Peak-Winter Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of October - May	

Charges for Customer Voltage Level 1(CVL1)

Energy Charge:

	Non-Capacity	*Capacity*	*Total*	
Off-Peak-Summer	*$0.033949*	*$0.014400*	$0.048349	per kWh during the calendar months of June-September
Low-Peak-Summer	*$0.045252*	*$0.019195*	$0.064447	per kWh during the calendar months of June-September
Mid-Peak-Summer	*$0.058331*	*$0.024743*	$0.083074	per kWh during the calendar months of June-September
High-Peak-Summer	*$0.066634*	*$0.028264*	$0.094898	per kWh during the calendar months of June-September
Critical Peak-Summer			the greater of either 150% of the High-Peak-Summer Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of June-September	
Off-Peak - Winter	*$0.035910*	*$0.015232*	$0.051142	per kWh during the calendar months of October - May
Mid-Peak - Winter	*$0.042325*	*$0.017953*	$0.060278	per kWh during the calendar months of October - May
High-Peak - Winter	*$0.043979*	*$0.018655*	$0.062634	per kWh during the calendar months of October - May
Critical Peak-Winter			the greater of either 150% of the High-Peak-Winter Energy Charge or the average Market price per kWh for a Critical Peak Event during the calendar months of October - May	

Delivery Charges:

System Access Charge: $200.00 per customer per month

Charges for Customer Voltage Level 3 (CVL3)

Capacity Charge: $4.92 per kW of Maximum Demand

Charges for Customer Voltage Level 2 (CVL2)

Capacity Charge: $2.07 per kW of Maximum Demand

Charges for Customer Voltage Level 1 (CVL1)

Capacity Charge: $1.14 per kW of Maximum Demand

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10

(Continued on Sheet No. D-37.30)

GENERAL SERVICE METERED LIGHTING RATE GML

Availability

Subject to any restrictions, this rate is available to any political subdivision or agency of the State of Michigan having jurisdiction over public streets or roadways, for Primary or Secondary Voltage energy-only metered lighting service where the Company has existing distribution lines available for supplying energy for such service. Luminaires which are served under the Company's unmetered lighting rates shall not be intermixed with luminaires served under this metered lighting rate. Luminaire types in addition to those served on Rate Schedule GUL, such as light-emitting diode (LED) streetlights, may receive service under this Rate Schedule.

This rate is not available for resale purposes or for Retail Open Access Service.

Nature of Service

Secondary Voltage

Service under this rate shall be alternating current, 60-hertz, single-phase or three-phase (at the Company's option), 120/240 nominal Volt service for a minimum of ten luminaires located within a clearly defined area. Control equipment shall be furnished, owned and maintained by the Company. The customer shall furnish, install, own and maintain the rest of the equipment comprising the metered lighting system including, but not limited to, the overhead wires or underground cables between the luminaires, protective equipment, and the supply circuits extending to the point of attachment with the Company's distribution system. The Company shall connect the customer's equipment to the Company's lines and supply the energy for its operation. All of the customer's equipment shall be subject to the Company's approval. The customer shall not change the capacity requirements of the equipment owned by it without first notifying the Company in writing of such changes and the date that they shall be made.

Dusk to Midnight Service

Dusk to midnight service shall be the same as Secondary service except:

The customer shall pay the difference between the cost of the control equipment necessary for dusk to midnight service and control equipment normally installed for Secondary service. Circuits shall be arranged approximating minimum loads of 3 kW.

Primary Voltage

Service under this rate shall be alternating current, 60-hertz, single-phase or three-phase (at the Company's option), Primary Voltage service for actual kW demands of not less than 100 kW for each point of delivery and where the customer guarantees a minimum of 4,000 annual hours' use of the actual demand. The Company will determine the particular nature of the voltage in each case. The customer shall furnish, install, own and maintain all equipment comprising the metered lighting system including, but not limited to, controls, protective equipment, transformers and overhead or underground metered lighting circuits extending to the point of attachment with the Company's distribution system. The Company shall furnish, install, own and maintain the metering equipment and connect the customer's metered lighting circuit to its distribution system and supply the energy for operation of the customer's metered lighting system.

Monthly Rate

Secondary Power Supply Charge

Energy Charge:

Non-Capacity	*Capacity*	*Total*	
$0.052873	*$0.000000*	$0.052873	per kWh for all kWh

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

(Continued on Sheet No. D-47.00)

GENERAL SERVICE METERED LIGHTING RATE GML

(Continued From Sheet No. D-46.00)

Monthly Rate (Contd)

Secondary Delivery Charge

System Access Charge:	$10.00	per customer per month
Distribution Charge:	$0.055922	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

Primary Power Supply Charge

Energy Charge:

Non-Capacity	*Capacity*	*Total*	
$0.025948	*$0.000000*	$0.025948	per kWh for all kWh

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

Primary Delivery Charge

System Access Charge:	$20.00	per customer per month
Distribution Charge:	$0.042091	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

Net Metering Program

The Net Metering Program is available to any eligible customer as described in Rule C11., Net Metering Program, who desires to generate a portion or all of their own retail electricity requirements using a Renewable Energy Resource as defined in Rule C11.B, Net Metering Program.

A customer who participates in the Net Metering Program is subject to the provisions contained in Rule C11., Net Metering Program.

Green Generation Program

Customer contracts for participation in the Green Generation Program shall be available to any eligible customer as described in Rule C10.2, Green Generation Program.

A customer who participates in the Green Generation Program is subject to the provisions contained in Rule C10.2, Green Generation Program.

(Continued on Sheet No. D-48.00)

GENERAL SERVICE UNMETERED LIGHTING RATE GUL

(Continued From Sheet No. D-50.10)

Monthly Rate

The charge per luminaire per month shall be:

Nominal Rating of Lamps (One Lamp per Luminaire) (1)

Type of Luminaire	Watts	Watts Including Ballast (2)	Lumens	Service Charge per Luminaire (4) Non-Capacity	Capacity	Total	Fixture Charge per Luminaire (4)
Mercury Vapor (3)	100	128	3,500	$ 6.21	*$ 0.00*	$ 6.21	$6.00
Mercury Vapor (3)	175	209	7,500	10.14	*0.00*	10.14	$6.00
Mercury Vapor (3)	250	281	10,000	13.64	*0.00*	13.64	$6.00
Mercury Vapor (3)	400	458	20,000	22.23	*0.00*	22.23	$6.00
Mercury Vapor (3)	700	770	35,000	37.38	*0.00*	37.38	$6.00
Mercury Vapor (3)	1,000	1,080	50,000	52.42	*0.00*	52.42	$6.00
High-Pressure Sodium (3)	70	83	5,000	4.03	*0.00*	4.03	$6.00
High-Pressure Sodium	100	117	8,500	5.68	*0.00*	5.68	$6.00
High-Pressure Sodium	150	171	14,000	8.30	*0.00*	8.30	$6.00
High-Pressure Sodium (3)	200	247	20,000	11.99	*0.00*	11.99	$6.00
High-Pressure Sodium	250	318	24,000	15.44	*0.00*	15.44	$6.00
High-Pressure Sodium	400	480	45,000	23.30	*0.00*	23.30	$6.00
Fluorescent (3)	380	470	20,000	22.81	*0.00*	22.81	$6.00
Incandescent (3)	202	202	2,500	9.80	*0.00*	9.80	$6.00
Incandescent (3)	305	305	4,000	14.80	*0.00*	14.80	$6.00
Incandescent (3)	405	405	6,000	19.66	*0.00*	19.66	$6.00
Incandescent (3)	690	690	10,000	33.49	*0.00*	33.49	$6.00
Metal Halide	150	170	9,750	8.25	*0.00*	8.25	$6.00
Metal Halide (3)	175	210	10,500	10.19	*0.00*	10.19	$6.00
Metal Halide	250	290	15,500	14.08	*0.00*	14.08	$6.00
Metal Halide	400	460	24,000	22.33	*0.00*	22.33	$6.00

(1) Ratings for fluorescent lighting apply to all lamps in one luminaire.

(2) Watts including ballast used for monthly billing of the Power Supply Cost Recovery (PSCR) Factor, Securitization and Securitization Tax Charges, Power Plant Securitization Charges and surcharges.

(3) Rates apply to existing luminaires only and are not open to new business.

(4) For customers who own their lighting fixtures and are assessed a Service Charge (but not a Fixture Charge), the charge per luminaire represents a 37.2% Power Supply Charge and a 62.8% Distribution Charge. For customers who do not own their lighting fixtures and are assessed both a Service Charge and a Fixture Charge, the charge per luminaire represents a

21.8% Power Supply Charge and a 78.2% Distribution Charge.

For energy conservation purposes, customers may, at their option, elect to have any or all luminaires served under this rate disconnected for a period of six months or more. The charge per luminaire per month, for each disconnected luminaire, shall be 40% of the monthly rate set forth above. However, should any such disconnected luminaire be reconnected at the customer's request after having been disconnected for less than six months, the monthly rate set forth above shall apply to the period of disconnection. An $8.00 per luminaire disconnect/reconnect charge shall be made at the time of disconnection except that when the estimated disconnect/reconnect cost is significantly higher than $8.00, the estimated cost per luminaire shall be charged.

For 24-hour mercury-vapor service, the charge per luminaire shall be 125% of the foregoing rates.

(Continued on Sheet No. D-52.00)

GENERAL UNMETERED EXPERIMENTAL LIGHTING RATE GU-XL

(Continued From Sheet No. D-54.01)

Facilities Policy (Contd)

Company-Owned Option (Contd)

D. The Company will determine the type and size of all experimental lighting fixtures to be offered under this rate. The list of approved fixtures is subject to modification at the sole discretion of the Company to accommodate new product development and advances in technology. Upon customer request, the Company shall provide a list of experimental lighting available under this rate.

E. The Company shall determine all associated equipment necessary to provide service under the Company-Owned Unmetered Experimental Lighting option.

F. Any charges, deposits or contributions may be required in advance of commencement of construction.

Customer-Owned Option

If it is necessary for the Company to install distribution facilities to serve a customer-owned system, contributions and/or deposits for such additional facilities shall be calculated in accordance with the Company's general service line extension policy. Any charges, deposits or contributions may be required in advance of commencement of construction.

Monthly Rate

Power Supply Charges

Energy Charge:

Non-Capacity	*Capacity*	*Total*	
$0.051599	*$0.000000*	$0.051599	per kWh for all kWh

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

Delivery Charges Customer-Owned Option

Distribution Charge:	$0.042405	per kWh for all kWh

Delivery Charges Company-Owned Option

Distribution Charge:	$0.052012	per kWh for all kWh
Fixture Charge per Luminaire:	$6.00	per month

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

General Terms:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Due Date and Late Payment Charge:

The due date of the customer bill shall be 21 days from the date of mailing. A late payment charge of 2% of the unpaid balance, net of taxes, shall be assessed to any bill which is not paid on or before the due date shown thereon.

Determination of Monthly Kilowatt-Hours and Burning Hours per Month Based on 4,200 Burning Hours per Year:

The monthly kilowatt-hours shall be determined by multiplying the total capacity requirements in watts (including the lamps, ballasts, drivers, and control devices) times the monthly Burning Hours as defined below divided by 1,000. The customer shall not change the capacity requirements of the equipment owned by it without first notifying the Company in writing of such changes and the date that they shall be made, and modifying the lighting contract with the Company accordingly.

Jan	**Feb**	**Mar**	**April**	**May**	**June**	**July**	**Aug**	**Sept**	**Oct**	**Nov**	**Dec**	**Total**
457.8	382.2	369.6	306.6	264.6	226.8	252.0	298.2	336.0	399.0	432.6	474.6	4,200

Hours of Lighting:

Unmetered Experimental Lighting shall be burning at all times when the natural general level of illumination is lower than about 3/4 footcandle, and under normal conditions this is approximately one-half hour after sunset until approximately one-half hour before sunrise. Lighting service will be supplied from dusk to dawn every night and all night on an operating schedule of approximately 4,200 hours per year.

(Continued on Sheet No. D-54.03)

GENERAL SERVICE UNMETERED RATE GU

Availability:

Subject to any restrictions, this rate is available to the US Government, any political subdivision or agency of the State of Michigan, and any public or private school district for filament and/or gaseous discharge lamp installations maintained for traffic regulation or guidance, as distinguished from street illumination and police signal systems. Lighting for traffic regulation may use experimental lighting technology including light-emitting diode (LED). This rate is also available to Community Antenna Television Service Companies (CATV), Wireless Access Companies or Security Camera Companies for unmetered Power Supply Units. Where the Company's total investment to serve an individual location exceeds three times the annual revenue to be derived from such location, a contribution to the Company shall be required for the excess.

This rate is not available for resale purposes, new roadway lighting or for Retail Open Access Service.

Nature of Service:

Customer furnishes and installs all fixtures, lamps, ballasts, controls, amplifiers and other equipment, including wiring to point of connection with Company's overhead or underground system, as directed by the Company. Company furnishes and installs, where required for center suspended overhead traffic light signals, messenger cable and supporting wood poles and also makes final connections to its lines. If, in the Company's opinion, the installation of wood poles for traffic lights is not practical, the customer shall furnish, install and maintain suitable supports other than wood poles. The customer shall maintain the equipment, including lamp renewals, and the Company shall supply the energy for the operation of the equipment. Conversion and/or relocation costs of existing facilities shall be paid for by the customer except when initiated by the Company.

The capacity requirements of the lamp(s), associated ballast(s) and control equipment for each luminaire shall be determined by the Company from the specifications furnished by the manufacturers of such equipment, provided that the Company shall have the right to test such capacity requirements from time to time. In the event that said tests shall show capacity requirements different from those indicated by the manufacturers' specifications, the capacity requirements shown by said tests shall control. The customer shall not change the capacity requirements of the equipment owned by it without first notifying the Company in writing of such changes and the date that they shall be made.

Monthly Rate:

Power Supply Charges:

Energy Charge:

Non-Capacity	*Capacity*	*Total*	
$0.056660	*$0.016776*	$0.073436	per kWh for all kWh

This rate is subject to the Power Supply Cost Recovery (PSCR) Factor shown on Sheet No. D-4.00.

Delivery Charges:

System Access Charge:	$2.00	per customer per month
Distribution Charge:	$0.014975	per kWh for all kWh

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10.

(Continued on Sheet No. D-55.00)

(Continued From Sheet No. E-9.00)

E2. ROA CUSTOMER SECTION (Contd)

E2.5 Term, Commencement of Service, and Return to Company Full Service (Contd)

C. Return to Company Full Service – Non-Residential ROA Customers (Contd)

A ROA Customer returning to Company Full Service for whatever reason (including Retailer default, but excluding a Slammed ROA Customer) who failed to meet their two-year minimum term of service under ROA and/or failed to provide written notice in accordance with the notification requirements set forth in this rule, must pay the market-based rate as defined below until the customer has met the **greater** of (i) the minimum two-year term of ROA service or (ii) the written notice requirements under this Rule E2.5, Term Commencement of Service, and Return to Company Full Service. A 10% adder will be included in the market based rate for bills rendered during the June through September billing months for those Customers that violate the December 1 written notice requirements.

<u>Retailer Default</u>**:** If a Retailer defaults, a ROA Customer who returns to Company Full Service before the 60 days or December 1 notice period has elapsed shall pay the market-based rate as defined below until the Company has received the benefit of the 60 days' or December 1 notice, at which time the customer may elect to remain on Company Full Service for 12 months and pay the applicable Company Full Service rate for which the customer qualifies. All other customers who fail to give the required 60 days' or December 1 notice are subject to the Company's ability to supply their requirements.

<u>Slammed Customer</u>: In the event a ROA Customer returns to Company Full Service because the ROA Customer was Slammed by a Retailer, the Company will waive all notice and minimum term requirements. The ROA Customer who was Slammed shall be immediately reinstated to the customer's Company Full Service rate the customer was transferred from prior to being Slammed. In the event the Slamming of the ROA Customer is disputed and a determination made that the ROA Customer was not Slammed, the ROA Customer shall be backbilled at the market-based rate and be subject to all requirements of this Rule E2.5, Term, Commencement of Service, and Return to Company Full Service.

<u>State Reliability Mechanism</u> In the event that a ROA customer is subject to the State Reliability Mechanism (SRM) pursuant to Public Act 341 of 2016, their energy allotment will continue to be counted against the 10% cap as defined in Public Act 295 of 2008.

Subject to the notice and minimum term requirements above, a ROA Customer may return to Company Full Service under the following conditions:

<u>**Option 1** – 12-Month Service Commitment</u>: If the returning ROA Customer commits to Company Full Service for a minimum of 12 months, then the customer may take and pay for such service under any Company Full Service rate for which the customer qualifies. Any returning ROA Customer that commits to remain on Company Full Service for the subsequent 12 months and then fails to do so will be backbilled at the market-based rate as defined below using either interval demand and energy data or the customer's energy data or the customer's energy usage and the applicable rate class profile.

<u>**Option 2** – Short-Term Service</u>: If the returning ROA Customer chooses not to commit to Company Full Service for a minimum of 12 months, then the customer may take service under any Company Full Service rate for which the customer qualifies and shall pay the market-based rate as defined below using either interval demand and energy data or the customer's energy usage and the applicable rate class profile.

The market-based rate is the **greater of**:

(1) The returning ROA Customer's applicable Company Full Service Rate Schedule computed on a monthly basis **or**

(2) The returning ROA Customer's applicable Company Full Service Rate Schedule but with the Power Supply Charges modified to include MISO's Real Time Locational Marginal Price for its CONS.CETR node, plus allocated capacity costs associated with capacity purchases required to meet the returning ROA Customer's peak load, plus applicable transmission charges, and the Market Settlement Fee (MSF) of $0.002/kWh computed on a monthly basis.

(Continued on Sheet No. E-11.00)

(Continued From Sheet No. E-10.00)

E2. ROA CUSTOMER SECTION (Contd)

E2.5 Term, Commencement of Service, and Return to Company Full Service (Contd)

C. Return to Company Full Service – Non-Residential ROA Customers (Contd)

For ROA Non-Residential Customers that violate the December 1 written notice requirement, the market based rate shall be adjusted as follows:

(1) For market based rate (1) above, a 10% adder shall apply to the power supply costs for bills rendered during the June through September billing months.

(2) For market based rate (2) above, a 10% adder shall apply to the MISO Real Time Locational Marginal Price for its CONS.CETR node for bills rendered during the June through September billing months.

D. Return to Company Full Service – Residential ROA Customers

Only the ROA Customer may initiate the return to Company Full Service by contacting the Company. The Company has no obligation to verify that the ROA Customer is eligible to terminate the service under the terms of a contract with its Retailer.

Upon completion of the ROA Customer's bill cycle for ROA service, the ROA Customer may return to Company Full Service at the beginning of the customer's next billing cycle by giving the Company written notice. A ROA Customer who so notifies the Company shall be obligated to take Company Full Service from the Company for a minimum of twelve months and pay for such service at any Company Full Service residential rate for which the customer qualifies.

Written notice is required from all ROA Customers returning to Company Full Service, except for Retailer defaults or Slamming. Once the ROA Customer provides written notice to the Company of its intent to Return to Company Full Service, in accordance with the notification requirements set forth in this rule, the ROA Customer may not rescind its notice.

Slammed Customer: In the event a ROA Customer returns to Company Full Service because the ROA Customer was Slammed by a Retailer, the Company will waive all notice and minimum term requirements. The ROA Customer who was Slammed shall be immediately reinstated to the customer's Company Full Service rate the customer was transferred from prior to being Slammed.

State Reliability Mechanism In the event that a ROA customer is subject to the State Reliability Mechanism (SRM) pursuant to Public Act 341 of 2016, their energy allotment will continue to be counted against the 10% cap as defined in Public Act 295 of 2008.

(Continued on Sheet No. E-12.00)

RETAIL OPEN ACCESS RESIDENTIAL SECONDARY RATE ROA-R

(Continued From Sheet No. E-22.00)

RETAILER

Monthly Rate - Retailer:

Transmission Service:

Subject to Rule E1.5, Transmission Service must be obtained from the appropriate transmission service providers and the charges for such service shall be as specified in the Applicable FERC Open Access Tariff.

Real Power Losses:

The Retailer is responsible for replacing Real Power Losses of 7.239% on the Company's Distribution System associated with the movement of Power and for compensation for losses.

General Terms and Conditions:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Term and Form of Contract - Retailer:

All service under this rate shall require a written ROA Service Contract between the Company and a Retailer.

ROA CUSTOMER

Monthly Rate - ROA Customer:

ROA System Access Charge, Distribution Charge, General Terms, Minimum Charge and Due Date and Late Payment Charge:

The System Access Charge, Distribution Charge, General Terms, Minimum Charge and the Due Date and Late Payment Charge shall be as provided for under the ROA Customer's otherwise applicable Company Full Service rate.

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10. Customers taking ROA service on December 6, 2013 are excluded from the Power Plant Securitization Charges. This exclusion does not apply to customers first taking ROA service after December 6, 2013 or to customers taking service on December 6, 2013 who discontinue taking ROA service any time after December 6, 2013. Customers who discontinue taking ROA service any time after December 6, 2013 and who return to ROA service shall pay the Power Plant Securitization Charges applicable to the customer's otherwise applicable Company Full Service Rate Schedule.

State Reliability Mechanism for ROA:

Beginning June 1, 2018 all ROA customers may be subject to a State Reliability Mechanism Capacity Charge. This charge shall not apply to ROA customers for any planning year in which their Alternative Electric Supplier can demonstrate to the Commission that it can meet its capacity obligations by the seventh business day of February each year starting in 2018.

If a capacity charge is required to be paid in the planning year beginning June 1, 2018, or any of the three subsequent planning years, due to the Alternative Electric Supplier not meeting its capacity obligations, then the capacity charge is applicable for each of those planning years. Any capacity charged required to be paid any time after the first initial four-year period shall be applicable for a single year. The planning year is defined as being June 1 through the following May 31 of each year. The capacity charge paid by ROA customers will be the same amount as a Full Service Customer on the otherwise applicable Rate Schedule. Non-capacity charges shall not apply.

ROA Customer Switching Service Charge:

A $5.00 switching fee shall be charged the ROA Customer each time a ROA Customer switches (i) from one Retailer to another or (ii) from ROA to a Company Full Service rate. The ROA Customer may switch Retailers at the end of any billing month by having their new Retailer give the Company at least 30 days' written notice. The Company will notify the ROA Customer’s previous Retailer and new Retailer electronically of the effective date of the switch. The ROA Customer may choose to return to Company Full Service at the end of any billing month in compliance with Rule

E2.5 D., Return to Company Full Service - Residential ROA Customers. The ROA Customer Switching Service Charge shall not be applied (i) for the initial switch to ROA Service or (ii) at the time the ROA Customer returns to Company Full Service or another Retailer because the ROA Customer was Slammed by the Retailer.

Term and Form of Contract - ROA Customer:

Service under this rate shall not require a ROA Service Contract between the Company and a ROA Customer.

RETAIL OPEN ACCESS SECONDARY RATE ROA-S

(Continued From Sheet No. E-25.00)

ROA CUSTOMER

Monthly Rate - ROA Customer:

ROA System Access Charge, Distribution Charge, General Terms, Adjustment for Power Factor, Minimum Charge and Due Date and Late Payment Charge:

The System Access Charge, Distribution Charge, General Terms, Adjustment for Power Factor, Minimum Charge and the Due Date and Late Payment Charge shall be as provided for under the ROA Customer's otherwise applicable Company Full Service rate.

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10. Customers taking ROA service on December 6, 2013 are excluded from the Power Plant Securitization Charges. This exclusion does not apply to customers first taking ROA service after December 6, 2013 or to customers taking service on December 6, 2013 who discontinue taking ROA service any time after December 6, 2013. Customers who discontinue taking ROA service any time after December 6, 2013 and who return to ROA service will pay the Power Plant Securitization Charges applicable to the customer's otherwise applicable Company Full Service Rate Schedule.

State Reliability Mechanism for ROA:

Beginning June 1, 2018 all ROA customers may be subject to a State Reliability Mechanism Capacity Charge. This charge shall not apply to ROA customers for any planning year in which their Alternative Electric Supplier can demonstrate to the Commission that it can meet its capacity obligations by the seventh business day of February each year starting in 2018.

If a capacity charge is required to be paid in the planning year beginning June 1, 2018, or any of the three subsequent planning years, due to the Alternative Electric Supplier not meeting its capacity obligations, then the capacity charge is applicable for each of those planning years. Any capacity charged required to be paid any time after the first initial four-year period shall be applicable for a single year. The planning year is defined as being June 1 through the following May 31 of each year. The capacity charge paid by ROA customers will be the same amount as a Full Service Customer on the otherwise applicable Rate Schedule. Non-capacity charges shall not apply.

ROA Customer Switching Service Charge:

A $5.00 switching fee shall be charged the ROA Customer each time a ROA Customer switches (i) from one Retailer to another or (ii) from ROA to a Company Full Service rate. The ROA Customer may switch Retailers at the end of any billing month by having their new Retailer give the Company at least 30 days' written notice. The Company will notify the ROA Customer’s previous Retailer and new Retailer electronically of the effective date of the switch. The ROA Customer may choose to return to Company Full Service at the end of any billing month in compliance with Rule E2.5 C., Return to Company Full Service - Non-Residential ROA Customers. The ROA Customer Switching Service Charge shall not be applied (i) for the initial switch to ROA Service or (ii) at the time the ROA Customer returns to Company Full Service or another Retailer because the ROA Customer was Slammed by the Retailer.

Term and Form of Contract - ROA Customer:

All service under this rate has a minimum term of two years.

All resale service under this rate **shall** require a written ROA Service Contract, with a minimum term of two years, between the Company and a ROA Customer.

All service under this rate **shall** require a written ROA Service Contract, with a minimum term of two years, between the Company and a ROA Customer with a Maximum Demand of 300 kW or more.

For a ROA Customer with a Maximum Demand of less than 300 kW, service under this rate may, at the Company's option, require a written ROA Service Contract with a minimum term of two years.

A new ROA Service Contract will not be required for an existing ROA Customer who increases their demand requirements after initiating service unless new or additional facilities are required.

RETAIL OPEN ACCESS PRIMARY RATE ROA-P

(Continued From Sheet No. E-27.00)

RETAILER (Contd)

Monthly Rate - Retailer: (Contd)

General Terms and Conditions:

This rate is subject to all general terms and conditions shown on Sheet No. D-1.00.

Term and Form of Contract - Retailer:

All service under this rate shall require a written ROA Service Contract between the Company and a Retailer.

ROA CUSTOMER

Monthly Rate - ROA Customer:

ROA System Access Charge, Distribution Charge, General Terms, Adjustment for Power Factor, Substation Ownership Credit, Minimum Charge and Due Date and Late Payment Charge:

The System Access Charge, Distribution Charge, General Terms, Adjustment for Power Factor, Substation Ownership Credit, Minimum Charge and the Due Date and Late Payment Charge shall be as provided for under the ROA Customer's otherwise applicable Company Full Service rate.

This rate is subject to the Surcharges shown on Sheet Nos. D-2.00 through D-3.10 and the Securitization Charges shown on Sheet Nos. D-5.00 and D-5.10. Customers taking ROA service on December 6, 2013 are excluded from the Power Plant Securitization Charges. This exclusion does not apply to customers first taking ROA service after December 6, 2013 or to customers taking service on December 6, 2013 who discontinue taking ROA service any time after December 6, 2013. Customers who discontinue taking ROA service any time after December 6, 2013 and who return to ROA service will pay the Power Plant Securitization Charges applicable to the customer's otherwise applicable Company Full Service Rate Schedule.

State Reliability Mechanism for ROA:

Beginning June 1, 2018 all ROA customers may be subject to a State Reliability Mechanism Capacity Charge. This charge shall not apply to ROA customers for any planning year in which their Alternative Electric Supplier can demonstrate to the Commission that it can meet its capacity obligations by the seventh business day of February each year starting in 2018.

If a capacity charge is required to be paid in the planning year beginning June 1, 2018, or any of the three subsequent planning years, due to the Alternative Electric Supplier not meeting its capacity obligations, then the capacity charge is applicable for each of those planning years. Any capacity charged required to be paid any time after the first initial four-year period shall be applicable for a single year. The planning year is defined as being June 1 through the following May 31 of each year. The capacity charge paid by ROA customers will be the same amount as a Full Service Customer on the otherwise applicable Rate Schedule. Non-capacity charges shall not apply.

ROA Customer Switching Service Charge:

A $5.00 switching fee shall be charged the ROA Customer each time a ROA Customer switches (i) from one Retailer to another or (ii) from ROA to a Company Full Service rate. The ROA Customer may switch Retailers at the end of any billing month by having their new Retailer give the Company at least 30 days' written notice. The Company will notify the ROA Customer’s previous Retailer and new Retailer electronically of the effective date of the switch. The ROA Customer may choose to return to Company Full Service at the end of any billing month in compliance with Rule E2.5 C., Return to Company Full Service - Non-Residential ROA Customers. The ROA Customer Switching Service Charge shall not be applied (i) for the initial switch to ROA Service or (ii) at the time the ROA Customer returns to Company Full Service or another Retailer because the ROA Customer was Slammed by the Retailer.

Term and Form of Contract - ROA Customer:

All service under this rate has a minimum term of two years.

All resale service under this rate **shall** require a written ROA Service Contract, with a minimum term of two years, between the Company and a ROA Customer.

All service under this rate **shall** require a written ROA Service Contract, with a minimum term of two years, between the Company and a ROA Customer with a Maximum Demand of 300 kW or more.

For a ROA Customer with a Maximum Demand of less than 300 kW, service under this rate may, at the Company's option, require a written ROA Service Contract with a minimum term of two years.

A new ROA Service Contract will not be required for an existing ROA Customer who increases their demand requirements after initiating service unless new or additional facilities are required.